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For most companies the

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- Electric Utility Industry - Worldwide
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- Refining & Gas Processing Industry - Worldwide
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- Drilling & Well Servicing Industry - Worldwide

- United States & Canada E&P
- Texas E&P
- Houston & Gulf Coast E&P
- Mid Continent & Eastern US E&P
- Rocky Mountain & Western US E&P
- Offshore E&P
- International E&P (outside North America)

Directory Numbers (latest counts)

Directory	Listings	HQ Offices	Personnel	Emails	Phone	Fax	Website
Pipeline	22,584	7,955	67,162	52,951	46,409	21,868	6,328
Refining & Gas Processing	20,873	8,726	58,369	45,344	39,455	20,031	6,462
Petrochemical	18,882	8,264	50,755	38,598	35,863	19,268	5,911
Liquid Terminals	8,457	2,983	28,325	22,693	19,142	8,933	2,637
Gas Utility	13,768	6,645	47,288	37,118	31,035	15,903	4,873
Electric Utility	27,586	13,117	81,906	62,193	49,642	25,432	9,160
Drilling & Well Servicing	15,275	6,745	37,279	28,303	23,639	12,974	3,691
Offshore E&P	9,197	3,842	30,382	25,032	16,240	8,518	3,313
International E&P	10,796	4,647	25,495	16,684	16,869	7,459	2,818
United States & Canada E&P	38,595	23,500	81,713	51,098	54,145	27,242	6,758
Texas E&P	11,760	7,820	31,857	22,614	19,578	9,921	3,101
Houston & Gulf Coast E&P	10,403	6,307	32,722	24,387	18,347	9,409	3,626
Mid Continent & Eastern US E&P	12,370	8,407	29,854	18,954	20,142	8,900	2,576
Rocky MTN & Western US E&P	9,539	6,256	21,603	13,119	13,860	6,710	1,647

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CO_2: EOR and Sequestration

Reserves substantial in marginal US gulf fields
Oxygen assists in refinery process intensification
Black Sea region stands at energy crossroads

OIL&GAS JOURNAL®

Dec. 7, 2009
Volume 107.45

CO_2: EOR and Sequestration

Regular Features

Cover

The CO_2 injection header is in Wyoming's Beaver Creek field. Devon Energy Corp. started injecting CO_2 in July 2008 for enhancing oil production from the field's Madison limestone-dolomite formation. By mid-2009, oil production from the Madison had increased to 1,200 b/d compared with 320 b/d before CO_2 injection. The photo above shows the field's CO_2 recycle compression. The petroleum industry's long history of successful CO_2-EOR operations can make substantial contributions to improve and accelerate deployment of carbon capture and storage projects. For instance, industry has developed sophisticated technologies for oil and gas operations that can be applied to CO_2 storage integrity as discussed in the first article in OGJ's special report—CO_2: EOR and Sequestration—starting on p. 20. A second article, p. 41, discusses the likelihood of more CO_2-EOR projects starting as new CO_2 supplies become available. Photos from Devon Energy.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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Dec. 7, 2009

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General Interest — Quick Takes

Utility groups urge derivatives-reform caution

Three trade associations representing natural gas and electric utilities urged leaders of two US Senate committees considering over-the-counter derivatives reform to not unwittingly cut utilities off from critical financial markets.

American Gas Association Pres. David N. Parker, Edison Electric Institute Pres. Thomas R. Kuhn, and Electric Power Supply Association Pres. John E. Shelk said in a Nov. 23 letter to leaders of the Senate Agriculture and Banking committees that utilities use OTC derivatives to hedge against price volatility.

Seventy of the associations' member companies also signed the letter to Christopher J. Dodd (D-Conn.), who chairs the Banking Committee, and Richard C. Shelby (R-Ala.), its ranking minority member; and Blanche L. Lincoln (D-Ark.), who chairs the Agriculture Committee, and Saxby Chambliss (R-Ga.), its ranking minority member.

The trade associations said their members do not contribute to overall systemic risk and should not be considered swap dealers or major system participants, which some members of Congress believe need to be more closely regulated. Independent oil and gas producers have made a similar argument to federal lawmakers considering commodities reforms.

AGA, EEI, and EPSA member companies rely on OTC derivatives to hedge prices and keep retail prices affordable, the association executives said in their letter. "When discussing any increased regulation of exchange and OTC derivatives markets, it is important to note that these transactions are not the source of systemic risk in the broader economy," they said. "In fact, the entire commodity market is less than 1% of the global OTC derivative market, and the energy commodity portion is yet a fraction of that 1%." The associations support the clearing of standardized derivatives between large financial dealers, where appropriate, through regulated central counterparties. But they oppose mandates that would require all or most OTC transactions be centrally cleared or executed on exchanges.

The associations also said they support increased authority of the Commodity Futures Trading Commission to prevent market manipulation. But they said this could be accomplished more effectively and at a lower cost through mechanisms such as a central data repository than through mandatory clearing.

Russia, EU sign warning pact on disruptions

Russia's Energy Minister Sergei Shmatko and European Union Energy Commissioner Andris Piebalgs have signed an agreement for an early warning of future disruptions of Russian gas supplies to the EU.

Under the agreement, Russia must notify the EU of any supply interruption whether due to maintenance, accidents, or commercial disputes. It covers gas, oil, and electricity. Third parties would be allowed to take part in the early-warning arrangement.

Shmatko said the agreement is not directed against Ukraine or any other transit countries and does not involve sanctions against them. He also said Russia would be signing a new agreement with Ukraine for bilateral cooperation and also indicated Russia would take part in upgrading Ukraine's pipelines.

Group pushes electric vehicles to cut oil use

A group of corporate chief executives has formed to promote cuts in US oil use through expansion of the electric-powered vehicle fleet.

The Electrification Coalition, Washington, DC, has published a plan to reduce oil consumption in the light-duty vehicle fleet to 2 million b/d in 2040 from 8.6 million b/d currently.

Its goal: that 75% of light-duty vehicle-miles traveled in that year be powered by electricity. "So long as the cars and trucks that power our economy are dependent on a single-fuel source, the majority of which is produced in hostile nations and unstable regions of the world and the price of which is increasingly volatile, our economy is at the mercy of events and actors largely beyond our control," the report's executive summary says.

At the center of the group's strategy is "an ambitious federal initiative to establish electrification ecosystems in a number of American cities" to support deployment of grid-enabled vehicles (GEVs), which are hybrids or fully electric vehicles able to recharge directly from the power grid. The group seeks deployment of 700,000 GEVs in 6-8 cities during 2010-13 and 7 million GEVs in those and 20-25 other cities by 2018.

The 180-page report assumes a large role for the federal government. Among its policy recommendations are new or expanded tax breaks for electric-vehicle purchases, public charging equipment, and investments by utilities and power aggregators in information-technology upgrades. ✦

Exploration & Development — Quick Takes

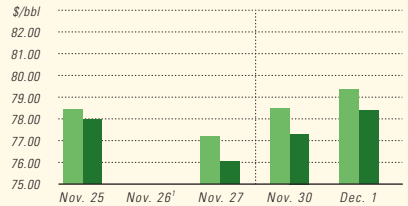
Petrobras to drill presalt strat test near Iara

Brazil's National Petroleum Agency (ANP) has authorized Petroleo Brasileiro SA (Petrobras) to drill a 21,000-ft stratigraphic test in what Petrobras describes as the "northern area of the Santos basin's presalt, contiguous to the Iara oil discovery."

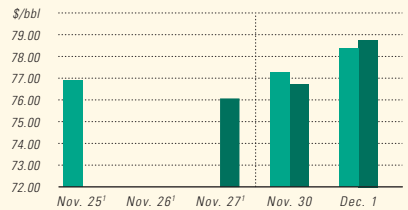
The SS-53 semisubmersible is to spud the well in mid-December outside the boundaries of blocks already bid, and Petrobras is to deliver well data to ANP after operations are concluded (see

Industry Scoreboard

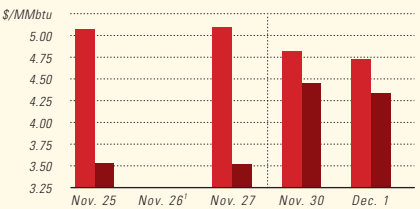
IPE BRENT / NYMEX LIGHT SWEET CRUDE



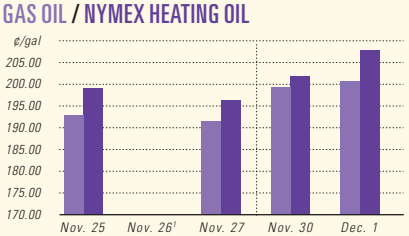
WTI CUSHING / BRENT SPOT



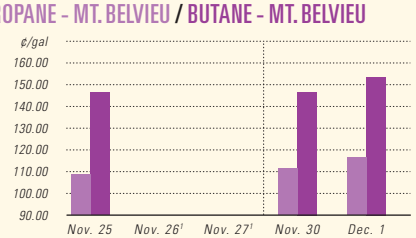
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



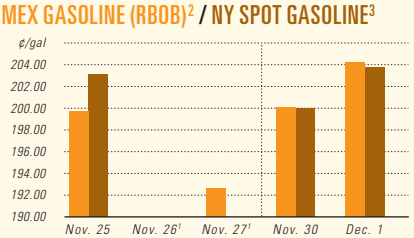
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[2] / NY SPOT GASOLINE[3]



[1]Not available [2]Reformulated gasoline blendstock for oxygen blending.
[3]Nonoxygenated regular unleaded.

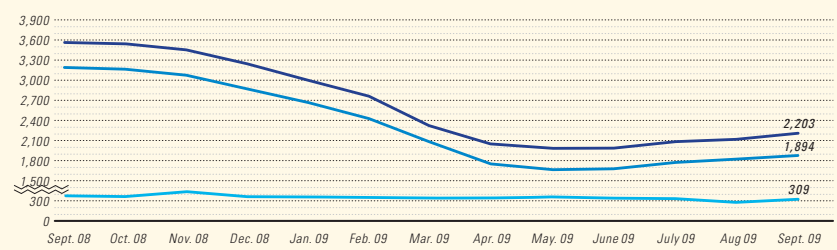
US INDUSTRY SCOREBOARD — 12/7

Latest week 11/20	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	8,992	8,943	0.5	9,026	8,998	0.3
Distillate	3,594	3,972	–9.5	3,595	3,964	–9.3
Jet fuel	1,456	1,433	1.6	1,413	1,556	–9.2
Residual	455	546	–16.7	537	613	–12.4
Other products	4,199	4,366	–3.8	4,087	4,416	–7.5
TOTAL DEMAND	18,696	19,260	–2.9	18,658	19,547	–4.5
Supply, 1,000 b/d						
Crude production	5,412	4,910	10.2	5,272	4,938	6.8
NGL production[2]	2,250	1,945	15.7	2,022	2,088	–3.2
Crude imports	8,578	9,990	–14.1	9,131	9,791	–6.7
Product imports	2,583	2,995	–13.8	2,752	3,133	–12.2
Other supply[3]	1,349	1,665	–19.0	1,651	1,579	4.6
TOTAL SUPPLY	20,172	21,505	–6.2	20,828	21,529	–3.3
Refining, 1,000 b/d						
Crude runs to stills	14,341	14,591	–1.7	14,434	14,676	–1.6
Input to crude stills	14,641	15,098	–3.0	14,777	15,046	–1.8
% utilization	82.9	85.7	—	83.7	85.5	—

Latest week 11/20	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	337,808	336,789	1,019	320,828	16,980	5.3
Motor gasoline	210,085	209,082	1,003	200,476	9,609	4.8
Distillate	166,868	167,397	–529	126,694	40,174	31.7
Jet fuel-kerosine	42,388	43,819	–1,431	38,005	4,383	11.5
Residual	36,929	36,464	465	38,842	–1,913	–4.9
Stock cover (days)[4]			Change, %		Change, %	
Crude	24.3	24.1	0.8	21.9	11.0	
Motor gasoline	23.4	23.4	0.0	22.3	4.9	
Distillate	46.4	46.7	–0.6	31.5	47.3	
Propane	45.3	47.7	–5.0	48.5	–6.6	
Futures prices[5] **11/27**			Change		Change	%
Light sweet crude ($/bbl)	76.90	78.36	–1.46	52.50	24.40	46.5
Natural gas, $/MMbtu	4.83	4.43	0.40	6.52	–1.69	–25.9

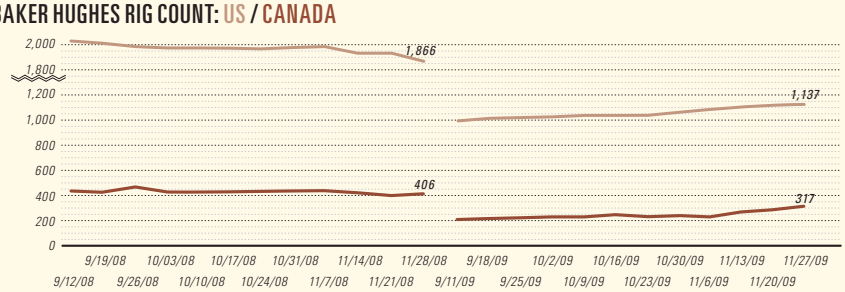
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, Wall Street Journal

BAKER HUGHES INTERNATIONAL RIG COUNT: TOTAL WORLD / TOTAL ONSHORE / TOTAL OFFSHORE



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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map, OGJ, June 16, 2008, p. 38).

"The region is eligible to compose the areas that will be the object of the Transfer of Rights with Compensation, once the Bill No. 5941/09 has been approved," the Petrobras announcement said. "The intention is to get stratigraphic information to create a better geologic knowledge of the area and the basis to the future development of the area."

A Petrobras-operated group drilled the 2008 Iara oil discovery in 7,314 ft of water 143 miles south of Rio de Janeiro and detected 30° gravity oil on a wire line test at 18,368 ft. The company has attributed 3-4 billion bbl recoverable to the Iara find, in which BG Group and Portugal's Galp Energia were partners.

Iara lies just northeast of Tupi, largest of the Santos presalt discoveries, to which Petrobras attributes 5-8 billion boe recoverable.

Hess gauges gas-condensate find off Libya

Hess Corp.'s Libyan subsidiary has drillstem-tested gas and condensate at a discovery well it drilled in 2008 in the Mediterranean east of Tripoli, Libya.

The A1-54/01 discovery well on the Arous Al-Bahar prospect encountered hydrocarbons in several intervals with a combined gross section of 500 ft in 2008 (OGJ Online, Dec. 17, 2008). Hess reentered the well and perforated a 300-ft carbonate interval.

The well, in the nonproducing offshore extension of the Sirte basin, flowed at a rate of 27 MMscfd of good quality gas and 533 b/d of condensate on a 52/64-in. choke on a drillstem test.

After completing tests, the Stena Forth sixth-generation dynamically positioned drillship is slated to return to finish drilling the A2-54/01 appraisal well 7 miles northwest of the discovery well.

Well A1-54/01 is in 2,807 ft of water 35 miles off Libya. Hess Libya Exploration Ltd. holds 100% working interest in Area 54, operated under an exploration and production-sharing agreement with Libya's National Oil Corp.

Origin Energy confirms extension off Tasmania

Origin Energy Ltd., Sydney, has confirmed an extension to the Trefoil gas discovery in the Bass basin permit T/18P off northern Tasmania with success at Trefoil-2 appraisal.

The company says several gas-bearing sands were intersected within the Eastern View Coal Measures and these will be analyzed more fully over the next few weeks using cores, wireline logs, reservoir pressure readings, and well samples.

The well has confirmed the continuity of the reservoir sands between the Trefoil-1 discovery and the Trefoil-2 well. The size of the resource will be determined when all the new data has been evaluated.

The Kan Tan IV semisubmersible rig is now moving to drill the Rockhopper-1 wildcat about 12 km to the north.

Both Trefoil and Rockhopper are close to the company's producing Yolla gas-condensate field.

Origin is operator with 39%. AWE Ltd., Sydney, has 47.5% and Innamincka Petroleum Ltd., Brisbane, has 5%.

Repsol YPF may join search effort off Guinea

Repsol YPF SA signed agreements with Hyperdynamics Corp., Sugar Land, Tex., under which the Spanish company may become operator with 37% interest in an exploration concession held by Hyperdynamics off Guinea, West Africa.

A letter of intent (LOI) gives Repsol YPF exclusive negotiating rights to take the 37% stake for $31.5 million. Becoming operator is subject to government and third-party approvals and consents. The two companies will work to sign definitive documents by Jan. 31, 2010, or the letter of intent terminates unless extended by both parties.

Before signing definitive documents, Repsol YPF has the right to participate with Hyperdynamics in evaluating geological and geophysical data, subject to licensing obligations with various seismic contractors. It also has the right to participate in the preparation for negotiations with Guinea's Ministry of Mines, Energy and Hydraulics regarding the terms of the clarification of the production sharing contract.

The letter of intent with Repsol YPF satisfies the clause in Hyperdynamics' existing LOI with Dana Petroleum PLC that envisioned Dana's option right to take up to an additional 27% of the concession if Hyperdynamics did not secure the participation of a major oil company by Nov. 30.

Hyperdynamics noted that Dana has made discoveries off Morocco and Mauritania. Repsol YPF is a partner with Anadarko Petroleum Corp. in the Upper Cretaceous Venus discovery off Sierra Leone. ✦

Drilling & Production — *Quick Takes*

Three Transocean deepwater units start up

Transocean Ltd. has started up three new ultradeepwater drilling units in the Gulf of Mexico and off Angola. Photo from Transocean.

Transocean Ltd. has started up three new ultradeepwater drilling units in the Gulf of Mexico and off Angola.

Most recently, Transocean said the Development Driller III semisubmersible had begun operations in the Gulf of Mexico under a 7-year contract with BP PLC (OGJ, Mar. 20, 2006, Newsletter).

The dual-activity rig can drill to 35,000 ft in 7,500 ft of water. The capacities can be upgraded to 37,500 ft in 10,000 ft of water.

Also in the Gulf of Mexico, the Transocean Discoverer Americas drillship began work for Statoil Gulf of Mexico under a 4-year contract (OGJ Online, Aug. 14, 2009).

The dual-activity drillship can drill to 40,000 ft in 12,000 ft of water.

Off Angola, the Transocean Petrobras 10000 drillship began operating under a 10-year contract with a unit of Petroleo Brasileiro SA (Petrobras). Transocean acquired the ship under a 20-year

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capital lease contract with P&M Drilling International BV, a joint venture of Petrobras and Mitsui.

The dual-activity ship has a water-depth capacity exceeding 10,000 ft (OGJ, Nov. 23, 2009, p. 41).

New Brunswick gets first Frederick Brook flow

Corridor Resources Inc., Halifax, reported the first significant flow of natural gas from the Mississippian Frederick Brook shale formation in New Brunswick and said the results are encouraging for future horizontal drilling and multistage fracturing.

Corridor Resources ran propane fracs in two intervals in the upper part of the Frederick Brook at the vertical Green Road G-41 well 4 km north of Elgin, NB.

The first frac resulted in placement of 46 tonnes of proppant in a black shale interval at 2,000-2,050 m. The second frac resulted in placement of 68 tonnes of proppant in a silty interval containing thin interbeds of sandstone at 1,850-1,900 m.

Commingled clean-up flow at the end of a 57-hr flow period was at a restricted rate of 4.1 MMscfd consisting of 85% natural gas and 15% propane frac fluid at a flowing wellhead pressure of 2,083 psi. A temperature log confirmed that both intervals were contributing to the flow.

Beach on target for oil production in Egypt

Beach Petroleum NL, Adelaide, is on target to produce first oil from Egypt following a successful test of a development well in its North Shadwan block in the Gulf of Suez off the Sinai Peninsula.

The company said its NS377-3 well flowed as much as 1,400 b/d of oil, which indicates a likely production rate of 1,500-2,000 b/d when the field is slated to be brought on stream in June 2010.

NS377-3 is the first development well of four planned for the NS377 and NS385 fields in the permit in which Beach has a 20% interest. Beach is operator, while others in the joint venture are Tri-Ocean Energy and Egyptian General Petroleum Co.

Beach aims to grow its reserves position to at least 20 million boe in Egypt during the next 5 years, predominantly focusing on the shallow waters of the Gulf of Suez. The company acquired its North Shadwan interest in 2008.

The concession contains three existing undeveloped oil discoveries and several prospective exploration targets. The fields were discovered by Saudi Amoco in the 1980s and lie in 20-40 m of water 2-4 km off Sinai.

The shallow water enables development via deviated drilling from onshore where all the production facilities are located. Oil will be delivered to the processing plant via an 11-km pipeline.

The next well in NS377 field will be exploration well Teen-1 followed by another development well, NS377-5. A different rig will be used to drill NS285-2 in NS385.

Combined ultimate recovery from these fields is expected to be 10-15 million bbl of oil. Full development is expected to cost as much as $60 million. ✦

Processing — *Quick Takes*

Valero to close Delaware City refinery

Valero Energy Corp., San Antonio, will permanently close its 210,000-b/d Delaware City, Del., refinery, citing financial losses caused by "very poor economic conditions, significant capital spending requirements, and high operating costs."

The announcement continued, "A safe and orderly shutdown of the refinery will commence immediately."

The shutdown will affect about 550 refinery employees. Valero notified employees Nov. 20 and said it will begin negotiating immediately with refinery unions regarding the effects of the plant closure and the employees' severance packages.

In the fourth quarter, the company will report a pretax charge of $1.7-1.8 billion, related primarily to "asset impairment," employee severance, and other shutdown costs.

Valero estimates the shutdown will reduce pretax operating expenses by about $450 million in 2010, including $125 million of noncash costs, and will reduce capital spending and turnaround costs by about $200 million through 2010.

In addition, the company expects to receive aftertax cash flows in 2010 of $600-700 million from inventory sales, "assuming current prices and other cash benefits from discontinued operations."

Valero Chairman and Chief Executive Officer Bill Klesse said the decision to close the refinery was "very difficult," adding, "… We have spent the last year diligently trying to avoid this situation."

Klesse noted that earlier this fall, Valero shut down the refinery's gasifier and coking operations to improve reliability and financial performance (OGJ, Sept. 14, 2009, p. 10). But "the refinery's profitability did not improve enough," he said.

In addition, Valero sought a buyer for the refinery, but "feasible opportunities have not materialized," adding, "At this point, we have exhausted all viable options."

The announcement said, "Valero remains committed to its marketing businesses in the Northeast and will continue to reliably supply its customers, partially through higher throughput rates at the company's other refineries."

Silver Eagle shutters Utah refinery

Silver Eagle Refining Inc. has shut down its 12,500 b/cd Woods Cross refinery in Utah on the suggestion of the US Chemical Safety Board and state officials.

CSB investigators found widespread safety problems at the refinery following a Nov. 4 in the plant's diesel unit. No one was injured and the fire was quickly contained.

CSB Chairman John S. Bresland said he asked on Nov. 13 that the refinery be shut down, and Silver Eagle executives "responded rapidly and positively" to the suggestion.

"The CSB team has developed a number of serious concerns about the integrity of the piping and equipment at various locations in the plant," Bresland said.

Bresland said he asked for the refinery to be shut down tempo-

rarily to correct potentially serious safety problems.

"This decision will obviously cost Silver Eagle some revenue in the short run, but I believe it is the right action to protect the long term interests of the company, its workforce, and the community which gives it license to operate," Bresland said.

The Nov. 4 accident was the second accident at the plant to be investigated this year. CSB already investigated a Jan. 12 fire in an atmospheric storage tank that seriously burned two employees and two contract workers.

ExxonMobil starts Rotterdam aromatics unit

ExxonMobil Chemical has started up an expansion of its Rotterdam aromatics plant (OGJ, Oct. 1, 2007, Newsletter).

The project boosted paraxylene capacity by 25% to 700,000 tonnes/year and benezene capacity by 20% to 830,000 tonnes/year.

The plant, owned and operated by ExxonMobil Chemical Holland BV, is now ExxonMobil's largest paraxylene production facility. The new unit uses proprietary ExxonMobil technology called PxMax. ✦

Transportation — *Quick Takes*

Haynesville operator to expand gathering

Regency Energy Partners LP, Dallas, will build Phase 2 in its expansion of the Logansport gathering system in North Louisiana, the company announced last week. Construction will begin early next month and target second-quarter 2010 for completion.

The $40 million expansion will move gas gathered from production in DeSoto Parish, La., to Regency's gathering system. The project also includes construction of an associated amine treating plant.

Regency will install 4.5 miles of 10-in. OD gathering lines, route 7.5 miles of 12-in. OD pipe through more than 17 sections of dedicated acreage in DeSoto Parish, and will add 3.2 miles of 24-in. OD pipe to connect into Regency's 24-in. Logansport Phase 1 expansion. The company will also install a gas-treating plant with inlet capacity of up to 300 MMcfd. In addition to the Phase 2 project, Regency will increase to 24 in. OD the previously announced 20-in. OD, 17-mile Logansport expansion. That project will interconnect with CenterPoint Energy Gas Transmission's Line CP.

Regency's Logansport system will then accommodate 450-485 MMcfd, said the company announcement, along the corridor that crosses the Gulf South East Texas lateral, as well as the proposed Energy Transfer Tiger Pipeline (OGJ, Nov. 2, 2009, p. 11).

Regency is also in the process of increasing the Logansport system's incremental interconnect delivery capacities to Tennessee Gas Pipeline and to Louisiana Intrastate Gas by about 100 MMcfd and 30 MMcfd, respectively. In September, Regency along with Alinda Capital Partners LLC and GE Energy Financial Services announced plans to build a $47 million pipeline extension of the Haynesville expansion North Louisiana to increase capacity on the Regency Intrastate Gas System.

The extension—called the Red River lateral—is adding about 100,000 MMbtu/day of capacity to the Haynesville expansion, bringing total project capacity to about 1.2 bcfd (OGJ Online, Oct. 28, 2009).

FERC approves Northwest's Piceance expansion

The US Federal Energy Regulatory Commission has issued a certificate to Northwest Pipeline GP, a majority owned subsidiary of Williams Cos. Inc., approving construction and operation of 15.5 miles of 30-in. OD mainline loop to bring additional natural gas from Piceance basin to the hub in Opal, Wyo.

The Sundance Trail Expansion will provide 150 MMcfd firm transportation capacity from the Greasewood and Meeker-White River hubs in Rio Blanco County, Colo., to the Opal hub area in Lincoln County, Wyo. At the Opal hub, producers have access to six interstate pipelines, including Northwest, Williams said.

The project will also replace and enhance Northwest's compression facilities at the Vernal compressor station in Uintah County, Utah. Northwest's main line is connected to the Piceance at the Greasewood hub through its Piceance lateral and the Meeker-White River hubs through Northwest's new Colorado Hub Connection pipeline and related facilities.

Williams began operations Aug. 7 at its 450-MMcfd Willow Creek gas processing plant in the Piceance basin. The Willow Creek plant is currently recovering about 20,000 b/d of natural gas liquids (OGJ, Nov. 16, 2009, p. 21).

Williams Pipeline Partners LP owns a 35% interest in Northwest.

Petrobras opens Urucu-Coari-Manaus line

Petroleo Brasileiro SA (Petrobras) began commercial operations on its Urucu-Coari-Manaus natural gas pipeline Nov. 27. The 661-km pipeline is part of Brazil's Growth Acceleration Program and includes seven branches totaling an additional 140 km, bringing gas from Brazil's Amazonian Solimoes basin to market. Branch lines extend from the trunk to Coari, Codajas, Anori, Anama, Caapiranga, Manacapuru, and Iranduba.

The Transpetro-operated pipeline's initial capacity measures 4.1 million cu m/day. Installation of two compressions stations between Urucu and Coari will increase the line's capacity to the contracted 5.5 million cu m/day by September 2010 when conversion of the associated power plants from fuel oil has occurred. Of the 5.5 million cu m/day, Petrobas says 5 million will supply the thermal market with the remaining 0.5 will go to industrial, commercial, residential, and vehicular customers.

The 196-km section between Coari and Anama encompasses the pipeline's longest course of flood areas. Some 6,000 floats and barrels helped support the line, with helicopters transporting individual section weighing 4.5 tons each, and 19 directional hiles drilled under river beds

The Urucu-Coari section uses 279 km of newbuild 10-in. OD pipeline to transport LPG, with the existing 8-in LPG line converted to natural gas transport. The 196-km Coari-Anama section includes a 20-in OD newbuild gas pipeline. The final 186-km stretch from Anama to Manaus includes the largest number of communities along the line, 135. ✦

Calendar

✦ Denotes new listing or a change in previously published information.

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Power-Gen International Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.power-gen.com. 8-10.

PIRA Natural Gas Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 14-15.

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2010

JANUARY

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Oil & Gas Maintenance Technology Conference & Exhibition Co-located with Pipeline Rehabilitation and Maintenance, Manama, Bahrain, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 18-20.

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World Future Energy Summit, Abu Dhabi, +971 2 4090 445, +971 2 444 3768 (fax), e-mail: ludoiva.sarram@reedexpo.ae, website: www.worldfutureenergysummit.com. 18-21.

Global Floating LNG Summit, London, +44 0 207 368 9300, e-mail: enquire@iqpc.co.uk, website: www.global-flngsummit.com. 20-21.

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mail: spedal@spe.org, website: www.spe.org. 24-27.

API Exploration and Production Winter Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 25-29.

Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 26-27.

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API/AGA Joint Committee on Oil and Gas Pipeline Welding Practices Conference, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 27-29.

Annual Gas Arabia Summit, Abu Dhabi, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. Jan. 31- Feb. 3.

International Process Analytical Technology Forum (IFPAC), Baltimore, (847) 543-6800, (847) 548-1811 (fax), e-mail: info@ifpacnet.org, website: www.ifpac.com. Jan 31-Feb 4.

FEBRUARY

Deep Offshore Technology International Conference & Exhibition, Houston, (713) 963-6271, (713) 963 6296 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 2-4.

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Russia Offshore Annual Meeting, Moscow, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 2-4.

Global Petrochemicals Conference & Annual Meeting, Vienna, Austria, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. Feb 9-11.

SPE International Symposium & Exhibition of Formation Damage Control, Lafayette, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

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Laurance Reid Conditioning Conference, Norman, Okla., (512) 970-5019, (512) 233-2877 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 21-24.

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renewableenergyworld-events.com. 23-25.

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Nitrogen + Syngas International Conference and Exhibition, Manama, +44 20 7903 2058, +44 20 7903 2172 (fax), e-mail: cruevents@crugroup.com, website: www.nitrogenandsyngas2010.com. Feb. 28-Mar. 3.

MARCH

APPEX Conference, London, +44 0 20 74341399, +44 0 20 74341386 (fax) website: www.appexlondon.com. 2-4.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 2-4.

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SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-9.

Purvin & Gertz LPG Seminar, The Woodlands, Tex., (713) 331-4000, (713) 236-8490 (fax), website: www.purvingertz.com. 8-11.

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International E&P	10,796	4,647	25,495	16,684	16,869	7,459	2,818
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Journally Speaking

Gloomy refining economics

Marilyn Radler
Senior Editor-Economics

Refining economics have been quite gloomy this year, and the outlook is not particularly good.

Refiners are shutting in capacity in order to shore up margins in light of dismal demand for transportation fuels and heating oil. As KBC Market Services noted in a recent Weekly Oil Comment, some of the refinery closures will be permanent, while others are open to offers from anybody who might be willing to buy the refineries.

The analysts explain that Europe's largest independent refiner Petroplus operated at only 61% of capacity during this year's third quarter. The company's Teesside refinery in the UK has been closed for most of 2009, and probably will be converted into a storage facility. The fate of Royal Dutch Shell PLC's Stanlow refinery could be the same, and Total SA's Dunkirk refinery in France is shut down. Others in Europe are operating at reduced capacity.

In the US, Sunoco Inc. shut down its refinery in Eagle Point, NJ, and sold its Tulsa refinery. Valero Energy Corp. announced that it intends to permanently shut down its 210,000-b/d Delaware City, Del., refinery, citing financial losses caused by very poor economic conditions, significant capital spending requirements, and high operating costs.

In its November Oil Market Report, the International Energy Agency looked at changes taking place in refining markets that might make for improved economics in the future.

IEA said although the outlook for refineries is bleak, particularly in the countries of the Organization for Economic Cooperation and Development, some necessary changes appear to be taking place. These changes could signal the end of the worst for refiners as they adapt to current conditions.

IEA noted that refinery profitability is typically tied to upgrading margins more so than to hydroskimming margins, which historically have averaged below zero. But the recent removal of large volumes of heavy sour crude from the world oil market has crushed the light-sweet/heavy-sour spreads, thereby reducing upgrading margins.

At the bottom of the last refining profitability cycle in 2002, refineries shut in crude units and simply fed their vacuum towers with residue in order to supply the products market and lose as little money as possible. IEA cited recent OECD country data suggesting that today's markets have not allowed for this opportunity, such that the two potential sources of refining profits over the past 20 years have been temporarily removed.

Recent changes

Looking at utilization of upgrading units at US refineries, IEA found that in recent months, catalytic cracking unit throughputs moved above their 2008 levels.

"Given their bias towards gasoline production, this perhaps points to the reemergence of gasoline as the binding constraint on US refining activity. While encouraging, the continued weak premium for high quality gasoline components, such as alkylate, and strong gasoline imports, continue to limit gasoline's ability to restore refinery margins," IEA said.

In contrast, weak hydrocracking throughputs—and IEA adds, more importantly, weak coking unit throughputs—demonstrate a response to weak distillate markets and the narrowing of heavy sour crude discounts. This suggests that refiners are adapting to current market circumstances.

There have also been big changes in global crude flows that have impacted refiners. US imports of crude from Saudi Arabia have dropped to about 700,000 b/d from about 1.5 million b/d, while imports of crude from Mexico fell to about 1 million b/d in August from a 5-year average of 1.6 million b/d.

Imports from Canada have increased, and refiners have had to adapt to new crudes that have offset some of the large declines in imports from Saudi Arabia and Mexico.

In addition, there have been changes in fuel oil markets resulting from narrower fuel oil cracks. IEA noted three important changes. First, fuel oil yields in the OECD have climbed, suggesting that refineries are responding to shifting product cracks. Second, above-average fuel oil exports from the former Soviet Union and Saudi Arabia may help restore typical fuel oil discounts, although this may be hampered by the rise in the volume of condensate produced.

The third change in the fuel oil market IEA cites is the start of long-term or permanent refinery closures, which will ring in a new normal state for the refining industry.

IEA said capacity rationalization will accelerate as uncompetitive capacity is marginalized and shut down. The industry is struggling with persistently weak profits, and while the initial changes are encouraging, more must be done. ✦

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Editorial

The purloined e-mails

What happens now that scandal clouds the scientific basis for worry about climate change?

Naturally, claims have arisen that incriminating e-mails to and from the University of East Anglia Climate Research Unit in the UK were taken out of context. Already, sympathizers say the messages should be ignored because they came to light through the wicked intrusions of a computer hacker.

Contexts, however, are clear enough. And, the messages can't be ignored, whatever routes they followed into the public domain. They came from scientists central to the international campaign for sacrificial remedies against global warming of human origin. And they show those scientists discussing the manipulation, even destruction, of data and the stifling of dissent.

Science and politics

While mitigating explanations may yet emerge, it is difficult to read the e-mails and not see corruption of science by politics. The e-mail writers showed unscientific concern for policy outcomes and an eagerness to shut views in conflict with their own out of debate. These are not obscure lab drones on some quirky crusade. They're celebrities of global-warming politics, whose reports drive findings of the Intergovernmental Panel on Climate Change, the citadel of climate alarmism. And they've been caught acting with apparent political motivation.

So what now?

Doubters of IPCC orthodoxy, having been dismissed without a hearing as cranks by the popular media and some—as it turns out—of the academic press, feel vindicated. It would be unreasonable, however, for them to expect their view suddenly to prevail. Scheming e-mails from the other side of a politicized academic argument won't persuade the masses that human contributions to observed warming are minor and that, therefore, behavior modification mandated by governments can't much affect global average temperature.

On climate change, in fact, minds are made up, political positions are fixed, and capital is invested. So a swift reversal on climate change surely is unlikely. It's valuable, however, to ponder. If the East Anglia affair did somehow persuade a majority of free people that their climate anxiety was unwarranted, and if politicians changed agendas accordingly, a large section of the developed world's cultural fabric would have to be rewoven. For example:

- Subsidies for "green energy" would cease in the US, leaving behind real environmental calamities such as 30,000 or so wind turbines converted into prairie junk.
- Congress and the Obama administration would disentangle energy and greenhouse gas emissions in policy-making.
- The United Nations would refocus itself on international peace.
- The Nobel Foundation would rename the award it gave former US Vice-President Al Gore and IPCC the Propaganda Prize.
- The mass media would abandon pet inanities such as "scientific consensus" and "settled science" and learn to put research funding into fair perspective.
- Public school teachers, with fewer you-can-save-the-planet simplicities at hand, would find new ways to bolster their students' self-esteem.
- Greenhouse-gas emission allowances would vanish from the menu of risky ways by which traders get rich.
- The phrase "cap and trade" as it applies to greenhouse gases would recede into political oblivion.

This easily extendible list is fanciful, of course. These things won't soon happen. A sense of climatic doom has embedded itself in the institutional thinking, investment planning, and—therefore—political ambitions of the developed world. And a single news event won't disengage it. The event does, however, provide a reason to think about how different the world would be without global-warming hysteria—and to wonder if change in that direction would make the world lower important safeguards.

The debate

Human activity does change the climate. It alters landscapes and increases concentrations of greenhouse gases in the atmosphere. In terms of warming, the ramifications of those changes aren't known—at least not to the certain extent the scandalized e-mail writers seem to have wanted everyone to believe. Without continued research and honest debate among scientists—debate unencumbered by politics—the ramifications of those changes can't be known.

Among revelations from the e-mails purloined from the University of East Anglia, the most important is that such a debate has not yet occurred. ✦

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Industry CO_2 EOR experience relevant for carbon capture and storage (CCS)

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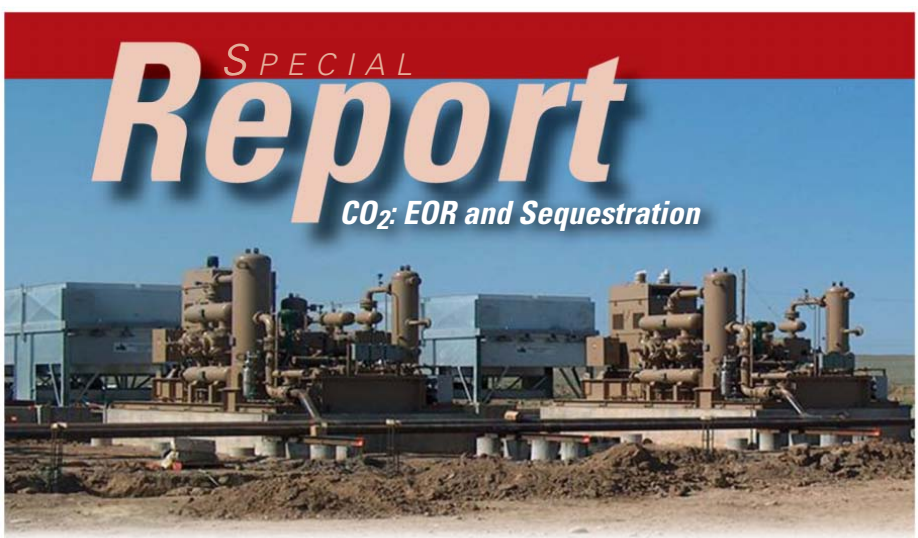


The petroleum industry's long history of successful carbon dioxide enhanced oil recovery (EOR) operations can make substantial contributions to improve and accelerate the deployment of carbon capture and storage projects.

For instance, industry has developed sophisticated technologies for oil and gas operations that can be applied to CO_2 storage integrity and monitoring applications.

Since the first patent for CO_2 EOR was granted in 1952, the oil and gas industry has spent many tens of billions of dollars developing and implementing CO_2 EOR technologies.

The first large-scale, commercial CO_2 EOR project began operation in 1972 at the SACROC field in West Texas, which continues in production today. Many more projects have started since then and by 2008 had reached a total of 112 projects (89% of total 126 globally) in the US and Canada.[1]

Underground geological storage of CO_2 is a promising technology for reducing greenhouse gas (GHG) emissions. Technology developed by the oil and gas industry for natural gas processing and CO_2 EOR can support the sound implementation of CCS.

The Intergovernmental Panel on Climate Change (IPCC) clearly considers EOR as a form of underground CO_2 storage. In CO_2 EOR, storage occurs as CO_2 displaces hydrocarbons from reservoir pore spaces and the injected CO_2 is trapped through capillary forces and other mechanisms.

The industry's processes and experiences relevant to CCS include separating (or capturing) CO_2 from oil or gas production, pipeline transportation to EOR projects, and design and operation of surface and subsurface systems for injection of CO_2.

Kinder Morgan has estimated that 655 million tons of CO_2 have been injected in Permian Basin EOR projects in the past 37 years. This amount is equivalent to the total CO_2 emissions of four to five 500 Mw capacity coal-fired power plants.

The 2008 OGJ EOR Survey reports that 15,373 wells (94% of all CO_2 EOR wells) including 9,144 producers and 6,229 injectors are operating in 105 CO_2 EOR projects in the US and 975 wells (6% of all CO_2 EOR wells) are in operation in other countries.

Industry CCS activity

Oil and gas industry companies participate in research consortia and fund research at major universities to answer

This article contains highlights of SPE 126446, "Industry Experience with CO_2-Enhanced Oil Recovery Technology," presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, San Diego, Nov. 2-4, 2009.

the technical and policy questions surrounding GHG management, including CCS.

The Carbon Dioxide Capture Projects (CCP & CCP2), Gulf Coast Carbon Center (GCCC), CO_2 Remove, Carbon Mitigation Initiative, and the Global Climate and Energy Project (GCEP) are prominent examples of such consortia.

The American Petroleum Institute is continually developing recommended practices, standards, and other information to ensure the ongoing safe and environmentally sound operation of CO_2 EOR operations. These same standards and practices, based on extensive industry experience should help government agencies or regulators prepare sound rules for CO_2 injection facilities and wells.

Additionally, API and International Petroleum Industry Environmental Conservation Association (IPIECA) have developed guidance on accounting for CO_2 emission reductions associated with CO_2 storage projects.

Fig. 1 compares the volumes of CO_2 injected by several oil and gas projects to the amount of CO_2 sequestration needed for a large coal-fired power plant.

It is generally accepted that injected CO_2 will react with the in situ formation water to create a weak carbonic acid solution, which is the basis for much of the concerns raised regarding CCS.

However, geochemists and others have found that the geochemical reactions that occur in geologic storage reservoirs can substantially affect the amount of carbonic acid formed. This is because CO_2 molecules in reservoirs have difficulty hydrating and are easily buffered due to in situ formation water's salinity and mineral content compared to molecules mixed in fresh water in metal or glass lab containers or testing devices.

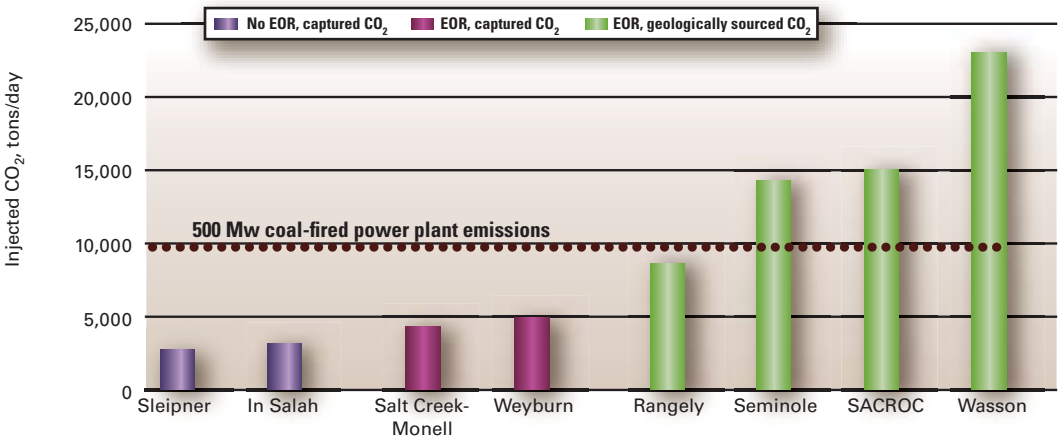
Cations from mineral salts and combinations of them present in reservoirs can limit decreases in the brine water's pH from CO_2 injection through mineral buffering and sustain much less corrosive environments than some researchers have claimed.[2]

Actual pH values of fluids in contact with well cements and pipe may average between 4.5 and 5.5, which are considered weakly acidic conditions compared to the much more acidic conditions created in lab tests by some researchers and by unrealistically low calculated values by some software models that attempt to predict pH conditions.

Smyth et al.[3] worked on a CO_2 geochemical laboratory testing project at the Gulf Coast Carbon Center, Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas

CO_2 INJECTION VOLUMES IN EOR VS. COAL-FIRED POWER PLANT SEQUESTRATION

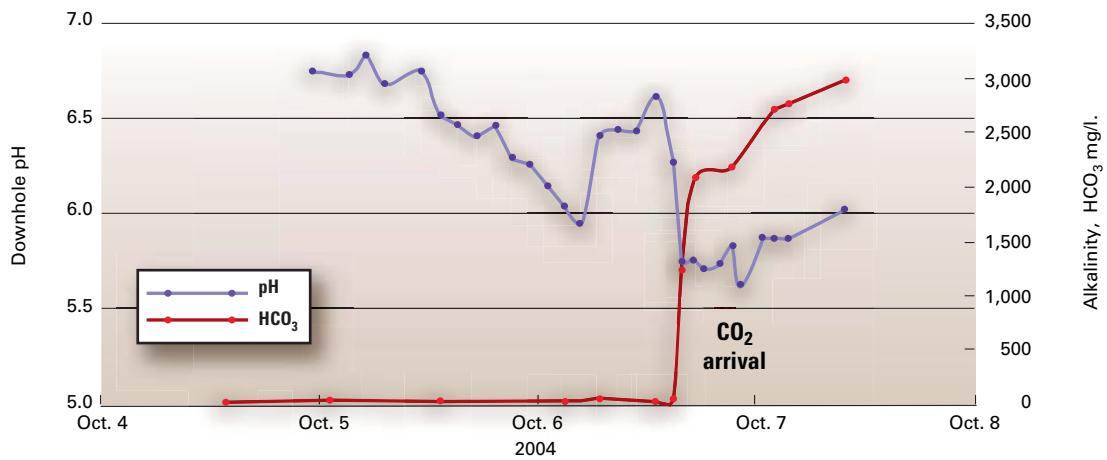
Fig. 1



Source: Heinrich et al. 2003

FRIO CCS TEST PROJECT, LIBERTY COUNTY, TEX.

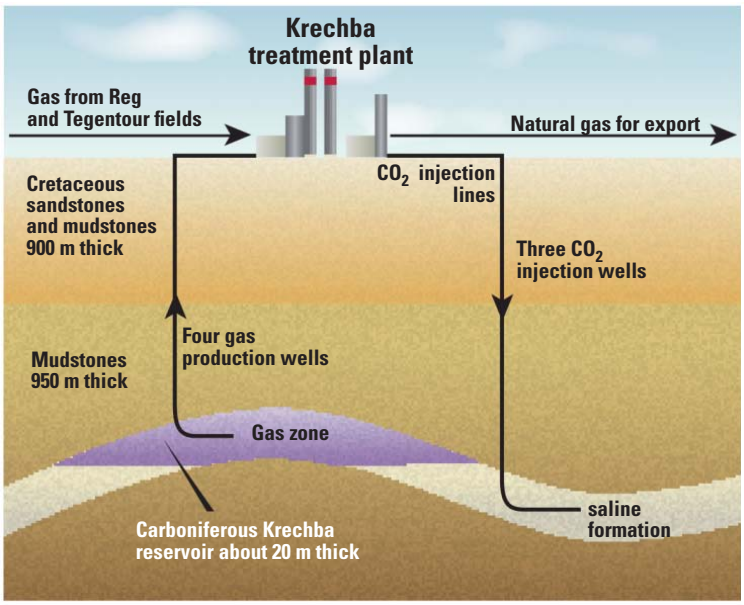
Fig. 2



Source: Gulf Coast Carbon Center, University of Texas at Austin

KRECHBA, ALGERIA, CO_2 INJECTION, STORAGE

Fig. 3



Source: BP PLC

at Austin (BEG/UT). They report that under simulated geochemical conditions, pH values can drop rapidly when CO_2 is introduced and then rebound to higher values.

Lab-generated pH values help explain why higher than expected pH values in Fig. 2 were measured in a U-tube device under downhole conditions at the Frio CCS test project.[4]

The mineral buffering effect may typically occur in storage and EOR reservoirs and should be simulated in lab testing procedures for well material (cement, pipe, etc.) selection and in software modeling applications to predict corrosive conditions (pH vs. time) during all phases of the project.

In 2007, API completed a study to compile CO_2 EOR injection well technologies representing the state of the art. A survey of operators, representing most US projects, was conducted to better document best practices and to review records of operational performance.

Survey results included many findings that had not been clearly presented before, particularly in the context of the concerns around CCS. For example, to cement wells, CO_2 EOR operators have used Portland cement-based well cement systems almost without exception and significantly, without adverse loss of CO_2 containment. These cost-effective, conventional cements were designed to have sealing and structural support properties suitable for the CO_2 EOR application.

The weak in situ acidic conditions help explain why operators have successfully used Portland cement-based systems to seal and support wells in CO_2 EOR projects. The extreme degradation of cement common in many lab test results is likely due to the absence of mineral buffering and not matching other reservoir conditions.

Zonal and integrity studies

During the last 9 years, representatives from government, academic, and industry organizations of the API Task Group on Annular Flow Prevention studied the causes and prevention of annular flow incidents and sustained casing pressure (SCP) in wells, which are recognized indicators of poor well cement integrity.

Two API recommended-practice publications (RP 65 Parts 1 and 2) were prepared and approved that describe preventive measures for any potential flow zone in any type of well including those in CO_2 zones. Preventative measures include key well planning, drilling, mechanical barrier, and cementing practices designed to help ensure cement integrity and isolation of potential flow zones.

Achieving cement integrity and zonal isolation in the presence of a potential annular flow of CO_2 can require not only the modification of the cement properties to facilitate control of migrating formation fluids and CO_2 but also several other practices including:

- A stable wellbore: no fluid losses or gains prior to, during, and after the cementing process.
- Adequate annular circulating flow clearances to help prevent abnormal displacement pressures.
- Proper mud-hole conditioning prior to cementing to remove cuttings, gelled mud, and excessive filter-cake.
- Spacer designs that help remove mud and leave pipe-formation surfaces water-wet for better cement bonds.
- Casing centralization to allow better placement of cement all around the pipe.
- Proper tripping requirements to help prevent negative effects by excessive swab-surge pressures.
- Proper drilling techniques to help ensure hole quality and minimize washouts, spiraling, and ovality.
- Well monitoring to help ensure cementing pressures, pump rates, and densities meet designed values.
- Waiting on cement (before start of well operations) for a sufficient period to allow undisturbed cement curing.
- Use of mechanical barriers when appropriate to help overcome problematic conditions.

Operators can minimize the risk of CO_2 migration by using multiple pressure barriers installed in wells in the form of multiple casing strings from the surface of the well to its total depth, mechanical pressure barrier devices (packers, etc.), and the cemented sections around each pipe, as explained in RP 65.

Note also that RP 65 effectively deals with preventing methane migration, which is much more difficult to prevent than CO_2 migration. This is because methane is an inert gas with more buoyancy than chemical reactive CO_2 molecules that can seal leak pathways by precipitating $CaCO_3$ scale.

CO_2 containment studies

- At US Environmental Protection Agency (EPA) and International Energy Agency meetings in March 2007, Koplos et al.[5] presented a well integrity study of Underground Injection Control injection wells that included data from EPA studies of Class II (CO_2 EOR) injection well mechanical integrity tests (MIT) and reported "No reported underground saltwater disposal well (USDW) impacts associated with wells with any known internal or external MIT failures in the 1983-92 period."
- The IEA GHG R&D Program's Monitoring Network reported on soil gas sampling measurements at the Rangely field CO_2 EOR project and concluded that the total amount of CO_2 leakage from the EOR zone was less than 0.01% over 15 years of CO_2 EOR operation. The IEA report also stated that there is no evidence of CO_2 leakage from the storage reservoir at other CCS projects including Weyburn, Frio, and Sleipner.
- Smyth et al.[3] at BEG/UT is evaluating CO_2 containment at the SACROC CO_2 EOR project. Smyth et al.[3] has reported that water sample testing from 68 wells and one spring indicate that no CO_2 leakage from the EOR zone into the USDW zones in the field has occurred after 35 years of CO_2 injection operations.
- Finally CCP has been studying the effects of CO_2 on well integrity via a wellbore sampling and laboratory analysis program under way since 2006.

CCS development practices

The oil and gas industry has a great record in sound development for operational surface facilities and wells in environmentally and politically sensitive site locations. This usually involves the use of health, safety, and environmental and well integrity standard industry practices with oversight by local regulators and community representatives.

The oil and gas industry has developed a highly sophisticated suite of technologies for petroleum operations that can be applied to CO_2 storage integrity monitoring applications. These intermittent and long-term monitoring methods include: wireline conveyed logging tools run in production, injection, and monitoring wells; seismic array data imaging; wellbore pressure monitoring by wellhead and downhole gauges; injection and production volumetric monitoring by flowmeters; subsurface to surface deformation measurements via tilt meters and satellite radar; gravity surveys, etc.

The applicability of these techniques is site specific, and selection requires an understanding of the site's subsurface characteristics, as well as the measurement capabilities of the various techniques in order to match the site's monitoring, verification, and accounting objectives.

Monitoring, whether direct (e.g., observation wells) or indirect (e.g., seismic), can only evaluate limited geographical areas-points at a point in time. Computer modeling serves as a proxy for visualization of what cannot be seen and for predicting CO_2 plume movements in the future.

Carbon dioxide injection wells are part of Krechba, one of eight Algerian gas fields that are part of the In Salah gas project. Operators inject CO_2 into a deep saline formation. Photo from BP PLC.

In Salah case history

Krechba is one of eight gas fields comprising the In Salah gas project in central Algeria that includes an industrial scale CO_2 storage project that has been in operation since 2004.[6]

CO_2 from several gas fields, which have a CO_2 content of 5-10%, is removed from the production stream to meet the sales gas export specification of 0.3% CO_2.

Rather than vent that separated CO_2 to atmosphere (as was normal industry practice for such gas plants), BP and its joint venture partner Sonatrach invested an incremental $100 million in a project to compress, dehydrate, transport, and inject that CO_2 into a deep saline formation downdip of the producing gas horizon.

The former StatoilHydro then joined the JV at production startup in August 2004. The investors derive no commercial benefit from the CO_2 storage at In Salah, so it is being used as an experimental and demonstration project to learn about CO_2 geological storage in deep saline formations.

The injection formation (Fig. 3) is a 20-m thick Carboniferous sandstone, 1,900 m below ground with around 15% porosity and 10 md permeability.

Three state-of-the-art horizontal CO_2 injection wells were drilled perpendicular to the stress field, and therefore the dominant fracture orientation, to maximize the injection capacity.

By the end of 2008, over 2.5 million tonnes of CO_2 had been stored underground. A Joint Industry Project (JIP) was set up to monitor the CO_2 storage using a variety of geochemical, geophysical, and production techniques over an initial 5-year period.

In Salah monitoring results

Monitoring data include geological, geochemical, geophysical, and satellite data.

Standard oil industry geological characterization data have been acquired, including wireline and LWD well logging suites, core sampling, and 3D seismic. Geochemical monitoring data collected to date include surface and soil gas monitoring, downhole gas measurements (head gas and isotubes samples), and production monitoring.

Different tracer chemicals (perfluorocarbons) have been used to "tag" the CO_2 injected at each injection well so that any CO_2 detected can be differentiated from the natural CO_2 in the subsurface and traced back to an individual injection well. Geophysical monitoring data will gain momentum in 2009 with the deployment of a downhole geophone detector string in a dedicated well to monitor microseismic events and the first time-lapse 3D seismic survey to monitor saturation and pressure changes.

Perhaps the most valuable, and initially surprising, monitoring method so far has been the use of satellite airborne radar interferometry to detect subtle ground deformation above the injection wells.[7]

Permanent scatterer interferometry is a multi-interferogram approach that draws on the phase changes occurring between a series of radar images and is specifically designed to overcome the effects of atmospheric noise and thereby determine surface movement histories over periods of several years.[8] Permanent scatterer interferometry gives an accuracy of around 5 mm/year and up to 1 mm/year for a longer-term average.

Surface uplift has been detected over all three of the In Salah CO_2 injection wells[9-11] with corresponding subsidence also observed over the gas production area. One of the first permanent scatterer interferometry datasets based on a 2-year time sequence of data[9] shows the observed surface uplift rate is around 5 mm/year.

More information on the MVA project at In Salah can be found in publications cited above and those listed as bibliography under In Salah and Wright et al.

Acknowledgments

This article is based on industry data obtained and studied by the API CCS work group, and the authors thank the work group for their contributions. The authors thank their respective employers, API, ExxonMobil, and Halliburton, for their support. Special thanks also go to Rebecca Smyth, and Jiemin Lu at the Gulf Coast Carbon Center, BEG/JSG, for Fig. 2, Brian Williams at BP for permission to add content for the In Salah case history, to Iain Wright, BP, and Philip Ringrose and Statoil for writing the MVA case history on the In Salah project, and Terry Knott, BP, for content. ✦

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Technology outpacing climate-change legislation, lawmakers say

Nick Snow
Washington Editor

Technology is moving ahead more quickly than legislation to address global climate change, three federal lawmakers agreed on Dec. 1. Congress won't be able to get back to work on the issue until 2010, they added.

Bills approved by the full US House and the Senate Environment and Public Works Committee haven't answered significant questions, US Sen. Byron L. Dorgan (D-ND) and US Rep. Fred Upton (R-Mich.) said during a forum on US climate and energy policy cosponsored by Newsweek and the American Petroleum Institute. But US Rep. Edward J. Markey (D-Mass.), who cosponsored the House bill, said the measure was an important first step in a long process.

"The measure is analogous to what we did in telecommunications," Markey said, noting that Congress passed bills in 1992, 1993, and 1996 that launched, respectively, the modern cable, wireless, and broadband systems while creating 2 million new jobs.

Emerging energy technologies could lead to a $2 trillion domestic industry if the US decided to actively support them, Markey said. "We have a choice. Right now, our energy strategy says 'Made by [the Organization of Petroleum Exporting Countries].' If we don't act, our new strategy will be to use products made in China. We can decide to release our own entrepreneurial spirit instead," he said.

The US Department of Energy has what effectively is the largest energy venture capital resource in history with federal economic stimulus funds it received to support new technology research and development, according to Dorgan. "I think there are unbelievably exciting things going on that we don't fully understand yet, but that will help us a lot," he said.

Outside government

The private sector is moving ahead too, other panelists said. US oil and gas companies collectively spend three times as much as the federal government in alternative and renewable energy R&D, API Pres. Jack N. Gerard said. US automakers plan to introduce new models in the next few years, including General Motors' Chevy Volt, which could drastically advance electric hybrid technology late in 2010, Upton pointed out.

The two climate bills currently before Congress could jeopardize such efforts and harm other US industries during a significant economic recession, Gerard argued. "We need to reset the discussion. The bill which passed the House and the one which the Senate EPW committee approved kill jobs and penalize specific industries," he said.

Upton said the bill that the House passed by seven votes on June 26 did not contain enough protections for businesses and consumers using electricity generated from coal. "I'm convinced that if we had the vote today, it would go down by 50 votes," he said, adding that an energy bill which the Senate Energy and Natural Resources Committee approved by 15 to 8 votes on June 17 was more balanced because it was truly bipartisan.

The bill, the American Clean Energy Leadership Act (S. 1462), has not been brought to the floor, Dorgan confirmed, partly because of Senate Republicans' efforts to block new legislation. "We're not getting bipartisan support on anything. We have to file cloture motions on noncontroversial issues," he said.

But Dorgan also questioned the heavy reliance on a carbon cap-and-trade program in the measures which have moved forward. "I'm not sure I'm comfortable with simply handing a new $1 trillion commodities market to Wall Street on Monday and hoping it will responsibly establish a price by Thursday," he said. "There are more direct ways for government to reduce emissions such as a carbon tax and command-and-control measures."

Senate hearing

Senate Energy and Natural Resources Committee leaders sent a similar signal as they opened a Dec. 2 hearing on greenhouse gas reduction policy options. Chairman Jeff Bingaman (D-NM) said that he has supported a cap-and-trade approach for some time, but added that carbon taxes, direct regulation, sector-specific approaches, and technological innovations may achieve the same results.

"It's important to note that these policies are not mutually exclusive," he continued. "In fact, it will more than likely be necessary to rely on a suite of these policies to ensure that we are effective in addressing global warming."

"We need to dispense with the blind faith in cap-and-trade that has dominated the past year of debate, or at least question whether that loyalty is truly warranted," said Lisa Murkowski (R-Alas.), the committee's ranking minority member. "A more inclusive debate would allow us to examine which policies are actually capable of reducing emissions while protecting, or even strengthening, the economy."

She said the Senate should explore other options, including pairing tax cuts with a price on emissions. Murkowski emphasized that she isn't suggesting that any approach for reducing emissions not be considered or planning to reduce any tax reform legislation, but has become concerned that the congressional climate change debate has become too narrow.

At the Newsweek-API event, Gerard said the oil and gas industry should get an opportunity to explore more of the US Outer Continental Shelf following 25 years of congressional moratoriums and presidential withdrawals. "We really haven't been given the opportunity to determine just how much oil and gas we have," he said, noting that production at Prudhoe Bay, which originally was expected to be 9 billion bbl, has passed 15 billion bbl, and the Gulf of Mexico, which once was considered depleted, has produced 40 billion bbl "and we've just scratched the surface."

Markey responded that the US can't indefinitely continue consuming 25% of the world's oil production while having only 2-3% of total global reserves. "I think we can be open-minded about more drilling, particularly for natural gas, but we need to change our overall approach," he said. "Clearly, [US President Barack H. Obama] has put health care up front, but the energy bill and financial reform are both on deck." ✦

Shell executive: CCS technology use needs to quicken

Nick Snow
Washington Editor

As the United Nations Climate Change Conference Dec. 7-18 in Copenhagen prepares to consider general strategies, a Shell International Exploration & Production official continues to ask practical questions about a specific climate strategy: carbon capture and storage.

"We think CCS has a great future. We understand it, but its deployment needs to be accelerated. Otherwise, it will be too expensive to retrofit power stations and large industrial facilities," John Barry, vice-president of unconventionals and enhanced oil recovery at the Royal Dutch Shell PLC division, said during a recent visit to Washington, DC.

Although EOR is part of his job title, Barry said the pumping of carbon dioxide into underground formations

to loosen trapped oil is a good initial demonstration of CCS technology, but only represents 1-2% of the total storage necessary to meaningfully address climate change.

It also has provided an early opportunity to examine practical aspects of transporting as well as storing CO_2, he suggested. "Several thousand kilometers of CO_2 pipelines exist because of EOR. They could help as we try to store manufactured CO_2," he said.

West Texas EOR operations, which have used naturally occurring CO_2 brought by the Cortez pipeline from Colorado since 1983, work because the formations are deep and the temperatures are cool, Barry said. "A few industrial companies are putting CO_2 into other pipelines, but they won't handle all that's being produced," he observed.

Shell and CCS

Shell has determined that its extensive oil and gas exploration and production experience could help it become a commercial CCS leader. It believes that energy efficiency should be the starting point for both existing and new assets, but that CCS also will be required. "We are not advocating it as a substitute for wind and other alternative energy technologies," said Barry, who started his 27-year career at the multinational oil company as a reservoir engineer. "They should be pursued as aggressively as possible, but it will take decades for their contributions to become meaningful."

Under one scenario, aggressive CCS deployment could cut 100 ppm of CO_2 emissions from projected 2010 levels, he added.

Shell and other majors can bring relevant skills to CCS development, but governments also need to play a strong leadership role, Barry said. They can help by providing funding for early demonstrations, developing legal frameworks which address pore space access and long-term liability questions, increasing public acceptance, and reaching international agreements to ensure CCS occurs outside industrially

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

FERC's interstate inquiry

The US Federal Energy Regulatory Commission sent an important signal Nov. 19 when it launched a cost-recovery investigation of three major interstate gas pipelines' rates.

Analysts said the inquiry involving Natural Gas Pipeline Co. of America (NGPL), Northern Natural Gas Co. (NNG), and Great Lakes Gas Transmission Co. was the first such move by FERC in more than a decade. It also was a result not of formally filed complaints, but of FERC staff's analysis of data routinely submitted by interstate pipelines.

FERC Chairman Jon Wellinghoff explained that in March 2008, FERC redesigned Form 2, on which the information is submitted, "to better facilitate the ability to make a meaningful assessment of the pipeline's cost of service and current rates."

Pipelines filed the revised form for the first time last April, and a staff analysis found that the three systems were recovering more costs than FERC allows, he noted.

'Not full story'

"Analysis and consideration of the Form 2 data is an important starting point for any commission action under Section 5 [of the Natural Gas Act]," Wellinghoff said, adding, "However, the review of Form 2 data is not the full story, and must be considered in conjunction with other factors, such as the costs and risks of litigation, the level of infrastructure investments, and the existence of a rate moratorium or comeback provision."

The case will proceed expeditiously because refunds are not possible, he said.

William F. Hederman, the former founding director of FERC's Market Oversight and Investigations Office, who now is a senior energy policy research analyst at Concept Capital, said, "Expediting also will be important to help investors get a handle of the extent of regulatory uncertainty this creates for pipelines."

FERC's decision to head down this path is a significant policy change, Hederman wrote Nov. 19. "The extent to which it changes regulatory risks remains to be seen. Nevertheless, it does appear, in our opinion, likely to increase regulatory risks for interstate gas pipelines," he wrote.

Not insulated

This is particularly true for systems above NNG, which is No. 15 on the Natural Gas Supply Association's list of "actual pipeline rate of return" for a 5-year average ending in 2007, Hederman said. Pipelines generally thought infrastructure reinvestment could insulate themselves from this action, he said. NGPL's inclusion despite parent Kinder Morgan's extensive infrastructure investments could change this, he said.

FERC's action was the top topic when the Interstate Natural Gas Association of America's board held its monthly teleconference on Nov. 30.

"The commission's decision to initiate Section 5's caught our attention and is a matter of concern," INGAA Pres. Donald F. Santa told OGJ afterward. "Several commissioners' statements show they also recognize the need to maintain the integrity of FERC's regulatory program and the capacity for pipelines to attract financing." ✦

"We think CCS has a great future. We understand it, but its deployment needs to be accelerated. Otherwise, it will be too expensive to retrofit power stations and large industrial facilities."

—John Barry, vice-president of unconventionals and enhanced oil recovery at the Royal Dutch Shell PLC division

developed nations, he said.

"We need a global rollout, a mechanism where countries using market-based processes have some allowances for early projects," Barry said. "There are coalitions of the willing: smaller groups of countries willing to set agreements, finding ways to link trading schemes. Somebody pays in the end. The money isn't magically created. But you get people supporting the most efficient CCS approaches. Politicians like it because it doesn't require new taxes."

Technical challenges include site selection ("I'm not proposing anywhere along the San Andreas Fault," Barry said), storage capacity, contaminants, cost containment, and monitoring. Public acceptance and establishing a commercial framework are the chief nontechnical challenges, he said.

Government policymakers should also be prepared to look beyond coal, he suggested. "To have a number in mind, capturing carbon from refineries and chemical plants could cost half as much as from coal-fired power stations," he said. Refineries and chemical plants' concentrated CO_2 have more early demonstration potential, according to Barry. "I see a whole lot of low-hanging fruit there," he said.

Eight projects

Shell has eight CCS projects under way, four of which are industrial scale. Those include one which will take CO_2 from the company's Pernis refinery and transport it by pipeline for storage in two depleted natural gas fields near Barendrecht in The Netherlands. The Dutch government approved the proposed project on Nov. 19 despite local opposition. Barry said that Karl-Heinz Wolf, a civil engineering and geosciences professor at Delft University of Technology, was shocked when he was heckled and called a traitor at a public hearing earlier.

"With the benefit of hindsight, we underestimated the potential for misunderstanding there," said Barry, adding that CO_2 already is piped into many vegetable greenhouses. "Shell is doing Barendrecht because it's cheaper to capture and store CO_2 from the Pernis refinery. The project's total costs per ton, with a small Dutch government subsidy, equal what we anticipate European carbon costs will be."

CCS costs will need to be competitive and not require government subsidies once the technology is developed and deployed, he emphasized. "It should cost less than carbon taxes once enough projects have been rolled out," he said.

Governments also will need to resolve the question of long-term liabilities, Barry maintained. "A company like Shell is frightened to take on open-ended liabilities," he said. "Operations should be accountable during injection and for a couple of years after. But it's more practical to have governments be responsible beyond that time. Australia already has passed a law assuming responsibility, and several European countries are considering it."

As for the UN climate change conference in Copenhagen, Barry said that he was optimistic that some space for CCS to happen globally could be opened. But he also was not prepared to say how far the 170 countries attending will go in explicitly endorsing it. ✦

Oil groups welcome delay of decision on ethanol limit

Oil industry groups welcomed a Nov. 30 decision by the US Environmental Protection Agency to postpone a decision on raising the amount of ethanol that can be blended into gasoline.

EPA told Growth Energy, a biofuels industry association, it would not immediately act on the group's March request for a waiver raising the ethanol ceiling to 15% from 10%.

The request came amid concerns that the stagnant US fuel market might not be able to absorb ethanol in the rising amounts mandated by Congress.

Automakers and manufacturers of small engines have resisted the increase, fearing engine damage, safety compromises, and warranty complications.

The decision

In a letter to Growth Energy, EPA said incomplete studies indicate fuel, engine, and emissions-control systems

in gasoline vehicles made in model years 2001 and later probably can accommodate fuel containing 15% ethanol (E15).

"However, we continue to evaluate the question of component durability when E15 is used over many thousands of miles, and there is an ongoing study being conducted by [the Department of Energy] that will provide critical data on this issue," EPA said.

DOE expects next August to complete a test of 19 vehicles assessing long-term emissions effects of higher ethanol blends on newer vehicles, EPA said.

DOE has data on two vehicles at present and expects to complete testing of 12 more vehicles by the end of May. EPA thus expects to have much of the data it needs for a decision by mid-June.

"Should the test results remain supportive and provide the necessary basis, we would be in a position to approve E15 for 2001 and newer vehicles in the midyear timeframe," EPA said, adding that the appearance of potential problems would further delay a decision until all testing is complete.

Industry reaction

The American Petroleum Institute called EPA's decision "sound" but expressed concern about the agency's willingness to consider a waiver for part of the vehicle fleet.

"API is actively supporting the studies that are currently under way," the association said in a statement.

While ethanol and other renewable fuels should help meet US energy demand, API said, "it's important that the short and long-term impacts of increasing the amount of ethanol blended into motor fuels be evaluated on the full vehicle fleet before a waiver decision is made."

National Petrochemical & Refining Association Pres. Charles Drevna said his group is "pleased" by EPA's postponement of the decision.

"EPA correctly recognizes that there is more study and comprehensive testing to be done to ensure that higher ethanol blends will be safe for consumers and not threaten the reliability of their fuels or operation of their vehicles, engines, and outdoor equipment," Drevna said.

The ethanol industry took a different view.

"This delay threatens to paralyze the continued evolution of America's ethanol industry," said Bob Dinneen, president and chief executive officer of the Renewable Fuels Association. He called for immediate approval of intermediate ethanol blends, such as 12%.

Dinneen called EPA's apparent focus on 2001 and newer vehicles "another worrisome development." ✦

CNPC signs new agreements with Sudan

Eric Watkins
Oil Diplomacy Editor

China National Petroleum Corp., apparently shrugging off environmentalists' concerns, has signed three oil and gas cooperation agreements with the government of Sudan.

The agreements consist of a memorandum of understanding on the second phase expansion of Khartoum refinery, advance payment for crude trading and an agreement to swap equity between CNPC's Block 6 and Malaysia State Oil's Block 5A.

No details were provided on the advance payment proposal or on expansion of the Khartoum refinery, owned 50-50 by CNPC and Sudan's state-owned Sudapet.

The Khartoum facility began operating in 2000 with a capacity of 2.5 million tonnes/year, and in 2006 was expanded to process 5 million tpy of oil. It supplies 80% of Sudan's refined oil.

However, CNPC said it also came to an agreement with Petronas to swap part of its 95% stake in Block 6 for Petronas' full stake in White Nile Petroleum Operating Co., which produces oil from Block 5A in Unity State.

Block 5A, which contains Thar Jath and Mala oil fields, was awarded in 2005 to WNPOC, a consortium comprised of operator Petronas 68.875%, Oil & Natural Gas Corp. 23.125%, and Sudapet 8%.

Political problems

To a certain extent, CNPC may have made the swap in an effort to avoid potential political problems brewing in the region around Block 6. But CNPC may instead face criticism from activists concerned about problems of pollution in Block 5A.

In mid-October, CNPC subsidiary China Petroleum Engineering & Construction Co. (CPECC) won a $260 million contract to develop Block 6, which straddles the border between Western Kordofan and South Darfur states.

"At present the only output from Block 6 is some 40,000 b/d from Fula field in West Kordofan, which started production in 2004," according to a recent report by The Economist Intelligence Unit.

However, EIU noted that in 2007 CNPC found 36 million bbl of recoverable oil in the western part of the block, and that it hopes to increase output to 60,000 b/d within 2 years.

According to EIU, "there is some risk that these developments will antagonize the main Darfur rebel groups or local tribal militias and the oilfields will be targeted for attack."

EIU noted that in 2007 and 2008, the Darfuri Justice and Equality Movement and a Kordofan militia were responsible for at least three instances of kidnappings of oil field workers in South Kordofan and the adjoining areas of South Darfur.

"While most were released, at least four Chinese oil workers were killed," EIU said.

Showdown in Hormuz?

Here's something that may alarm the oil and gas industry: Iran has given the Islamic Revolutionary Guard Corps command over naval operations in the Persian Gulf and Strait of Hormuz.

That's according to a report by the US Office of Naval Intelligence, which says the Iranians have undertaken the move as of a strategy to block international access to vital sea lanes in the event of a war.

As a reminder, oil movements through the strait account for 40% of all seaborne oil traded in the world, according to the US Energy Information Administration.

EIA also predicts that oil exports passing through the strait will reach 30-34 million b/d by 2020 from the current 15 million b/d.

Adverse impacts

Any closure of the strait would severely impact the industrialized world as most of the oil exported through the waterway travels to the US, Western Europe, and Asia. In fact, about 75% of Japan's oil needs pass through the strait.

While consumers would be hardest hit by any closure, so too would producers as an estimated 90% of oil exported from gulf exporters such as Saudi Arabia, Kuwait, and the UAE is carried on oil tankers through the strait.

Then too, some 2 million b/d of oil products, including fuel oil, are exported through the strait along with LNG, with exports from Qatar alone reaching 31 million tonnes/year.

The ONI report notes that Iran also relies on the strait to transport most of its oil exports, and that it would incur risks by imposing a blockade on the area.

"Closing the Strait of Hormuz would cause Iran tremendous economic damage, and therefore Iran would probably not undertake a closure lightly," ONI said, adding that "given the importance of the strait, disrupting traffic flow or even threatening to do so may be an effective tool for Iran."

Price surge

The ONI report follows an earlier research note by analyst Raymond James & Associates Inc. that said oil prices may surge to a record if conflict over Iran's uranium enrichment leads the oil producer to slash exports or block the Strait of Hormuz.

In October, Raymond James analysts saw a greater than 50% chance of military strikes against Iran over the next year, a scenario they say would prompt Iran to cut off oil exports and potentially block the strait.

"The market is aware of this, but seems to be factoring in extremely low probability it will happen," said Raymond James analyst Pavel Molchanov, who also noted that if Iran is attacked, oil prices could soar to a record higher than the $147/bbl they reached in July 2008.

As one of US Central Command's key missions in the gulf is to ensure the free flow of oil and energy supplies, a confrontation could well be shaping up. Let's hope it is merely a war of words. ✦

Contamination's impact

Meanwhile, according to a recent activist report, oil production in Block 5A—the very site of CNPC's swap—is contaminating water, spreading disease to humans and cattle, and threatening the world's largest inland wetlands.

"Oil exploration and exploitation in the oil fields of Mala and Thar Jath pose serious threats to human beings, livestock, and the environment," said Klaus Stieglitz, vice-chairman of the German NGO Sign of Hope.

Pointing to the central processing facility at Thar Jath, Stieglitz said that water flowing off the huge installation was a major source of contamination.

"Waters found in drilling pits at oil wells are another major source of contamination. Contaminants of both sources have already reached the drinking-water layers," he said.

Stieglitz cited the case of Rier, a village close to the Thar Jath processing facility, where concentrations of salts and contaminants such as cyanide, lead, nickel, cadmium, and arsenic have reached critical levels.

"The contamination has a serious impact on the daily life of the local population. In the village of Rier, the inhabitants do not use the water coming from their boreholes," he said.

"Locals who drink this kind of water can get diarrhea and a subsequent dehydration of the body, which might lead to death if untreated," Stieglitz warned.

"The heavy-metal concentrations of these waters will have a negative impact on the health situation of the some 300,000 inhabitants of the affected area, which covers 4,000 sq km," said Steiglitz, who urged WNPOC to treat the plant's water adequately and prevent seepage.

"To secure public health, the government must also improve the quality of drinking water dramatically and at the same time prevent an ecological catastrophe," he said. ✦

Mexico eyes risk contracts to offset Cantarell downturn

Eric Watkins
Oil Diplomacy Editor

Mexico's state-owned Petroleos Mexicanos and the Secretaria de Energia (Sener) are preparing risk contracts that will be offered to oil companies—international and domestic—in order to accelerate the search for oil and gas, according to local media.

Mexico's daily El Universal reports that the contracts are the result of concern over output generally, but especially at Cantarell, which represents a loss of 272.425 billion pesos/year ($20.859 billion) in tax revenue for the country, or 2% of estimated gross domestic product for 2009, at current oil prices.

The paper cites official letters 400-455 and COFEMER/09/3988 (Federal Regulatory Improvement Commission), dated Nov. 3 in which Sener urges regulatory institutions to speed up the procedures in the new legal framework that was approved with the recent energy reform.

Sener explains that it is urgent "to speed up the discovery of new oil fields and the incorporation of reserves, as well as increase Pemex's execution capacity, particularly through new contracting schemes so that specialized companies can support its activities."

Sener adds that it is necessary "to reverse the decline in national hydrocarbon production and develop technology to extract the petroleum found in deposits, particularly those located in deep waters."

Sener said, "The situation with what used to be Mexico's main oil field is worrisome, because since 2005 we have seen its decline lead to a production drop of nearly 770,000 b/d."

In September, Sener calculated that loss at 230 billion pesos ($17.611 billion), based on a price of $60/bbl at that time.

Sener said Cantarell's contribution to national production is steadily shrinking, since it was producing 2.2 million b/d in 2005, or 60% of total oil production.

By December, Pemex and Sener expect Cantarell to produce 550,000 b/d, or 21% of national petroleum production.

According to El Universal, the official predictions indicate that between 2009-17 an average of 423,000 b/d of oil will be produced from this field, and that by the end of that period it will produce 255,000 b/d, or only 8.4% of national production.

This situation, the official letters add, presents a challenge to the national petroleum industry, since it means replacing the petroleum and gas extracted from this asset with extraction at a large number of small and medium deposits throughout the national territory.

In the short term, Pemex must be able to develop new oilfields, which involves enormous complexity in terms of technical issues and execution, as well as considerable time for their development.

Sener maintains that it is urgent that Pemex be given the right to explore in deep waters of the Gulf of Mexico and begin the procedures necessary to obtain deeds of assignment for petroleum and surface exploration permits.

Sener explains that Pemex's new legal framework will allow it to act quickly and reduce red tape.

For now, the awarding of risk contracts and the purchase of materials will be aimed at developing key suppliers for priority and support areas, in order to decrease costs and delays in constructing rigs, laying pipelines, and drilling. ✦

Mexico cuts Pemex's budget for Chicontepec work

The Mexican government has slashed the allocation to state-owned Petroleos Mexicanos (Pemex) for Chicontepec oil development in 2010 by more than 60% from this year's level, according to local media.

Mexico's daily El Universal said "poor results, technical limitations, and execution problems" at Chicontepec have caused the Finance Secretariat and the Congress, particularly the Partido Revolucionario Institucional (PRI), to cut the budget for the technically challenging development.

According to Pemex, the Chicontepec complex of low-permeability reservoirs represents 39% of the country's total hydrocarbon reserves. But legislators and financial authorities slashed the investment plan for Chicontepec for the rest of the current administration.

Information from the Budget Decree approved for 2010 reveals that the allocation for the exploitation of the 29 fields in the Tertiary Gulf Oil Project (Chicontepec) totals $1.614 billion, which can be spent beginning Jan. 1.

Pemex also had planned to have available about $5.736 billion more for 2011 and 2012, but after the evaluation of the project, the commitment is for only $4.802 billion, or $919.231 million less.

This situation will force Carlos Morales Gil, Pemex EP director, to adjust activities that he had planned for 2010 in the region that includes Puebla and Veracruz: drilling 975 wells, repairing 371 large wells and 142 small wells, and building 66 km of pipelines.

Morales Gil told El Universal that Chicontepec will produce less oil this year than expected, and that it will produce only 43,000 b/d in 2010.

From Jan. 1 through Nov. 6 of this year, Chicontepec oil production averaged 29,000 b/d; the goal set in the budget was 58,000 b/d. ✦

GULF MARGINAL PRODUCTION—1

Reserves, revenues substantial in marginal Gulf of Mexico fields

Mark J. Kaiser
Louisiana State University
Baton Rouge

Experts may disagree on when world oil production will peak, but there is general agreement that marginal fields will contribute a greater percentage of world supply in the future.

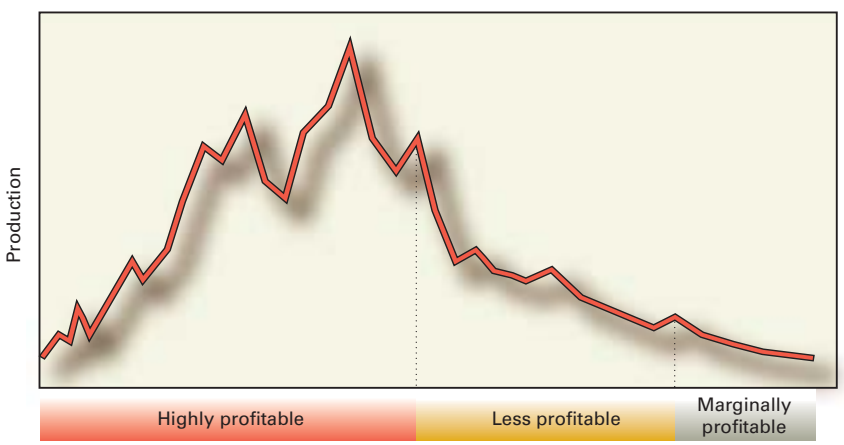
Each producing property is unique and has costs and benefits specific to each stage of its life cycle. As fields mature and operations transition into the later stages of their production cycle, decreasing revenue streams, higher operating costs, and fewer upside opportunities lead to declining profitability.

In this three-part series on marginal production in the Gulf of Mexico, we highlight the results of a recent Minerals Management Service study that estimated the marginal production and gross revenue streams associated with the inventory of producing structures circa January 2007.[1]

The cumulative hydrocarbon production from the inventory of producing assets is estimated to be 1.056 billion bbl of oil and 13.3 tcf of gas. Marginal production is expected to contribute 4.1% of the total oil production and 5.4% of gas production in the gulf.

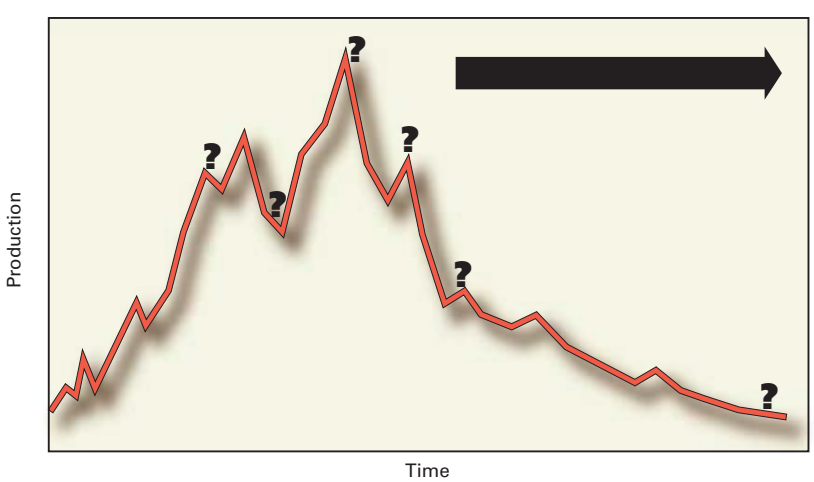
GENERIC REPRESENTATION OF PRODUCING ASSET PROFITABILITY OVER TIME

Fig. 1



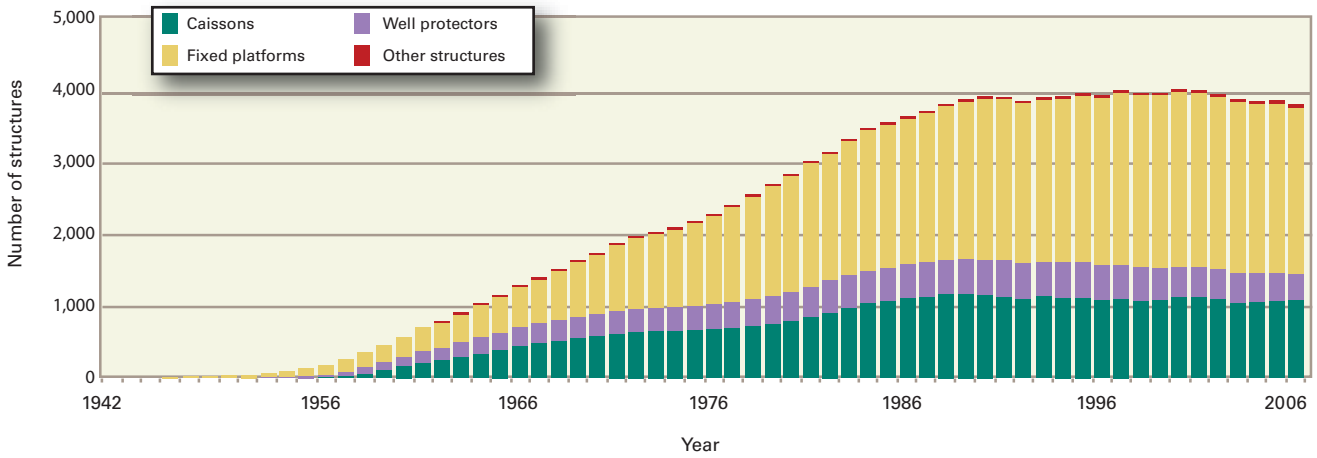
WHEN A STRUCTURE IS LIKELY TO ENTER MARGINAL PHASE

Fig. 2



Active Gulf of Mexico structures

Fig. 3



In Part 1, we review historical production characteristics of the gulf.

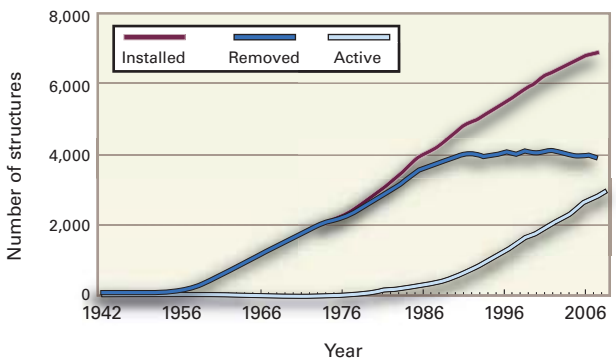
OCS operations

The Outer Continental Shelf (OCS) of the Gulf of Mexico is the most extensively developed and mature offshore petroleum province in the world.

More than 46,000 wells have been drilled in the OCS since offshore production began in 1947, and about 6,500 producing wells, 3,800 structures, and 33,000 miles of pipeline are currently used in the production of oil and gas.

Gulf of Mexico cumulative structures

Fig. 4

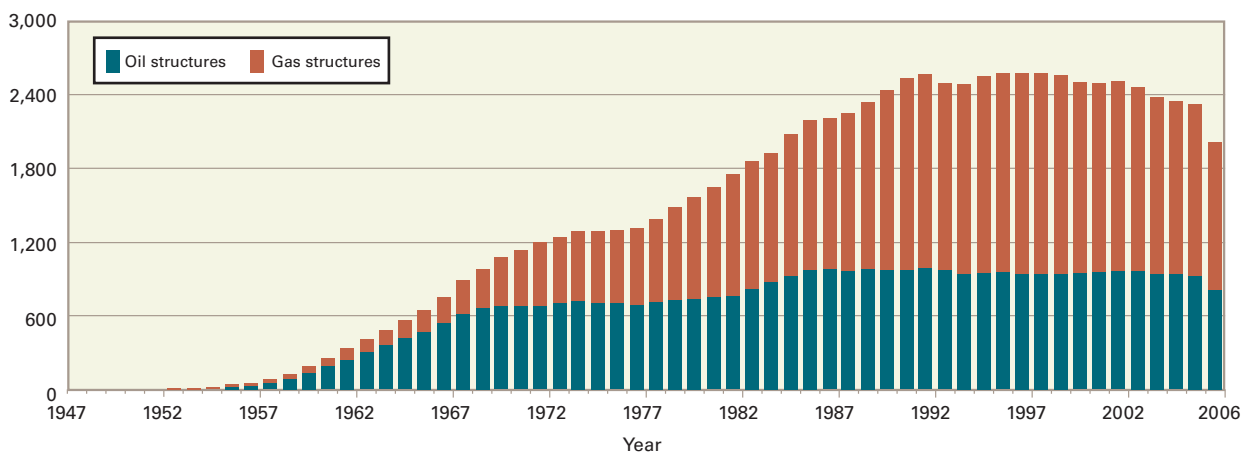


As of March 2009, there were 1,043 producing leases, 628 unitization agreements, and about 200 leases in suspension. In 2008, the Gulf of Mexico OCS produced more than 422 million bbl of oil and about 2.8 tcf of gas, roughly 25% and 13% of the US total.

Operating offshore is more complex and risky, and more capital intensive, than onshore environments. Offshore wells have higher operating costs than onshore wells and tend to be more sensitive to changes in

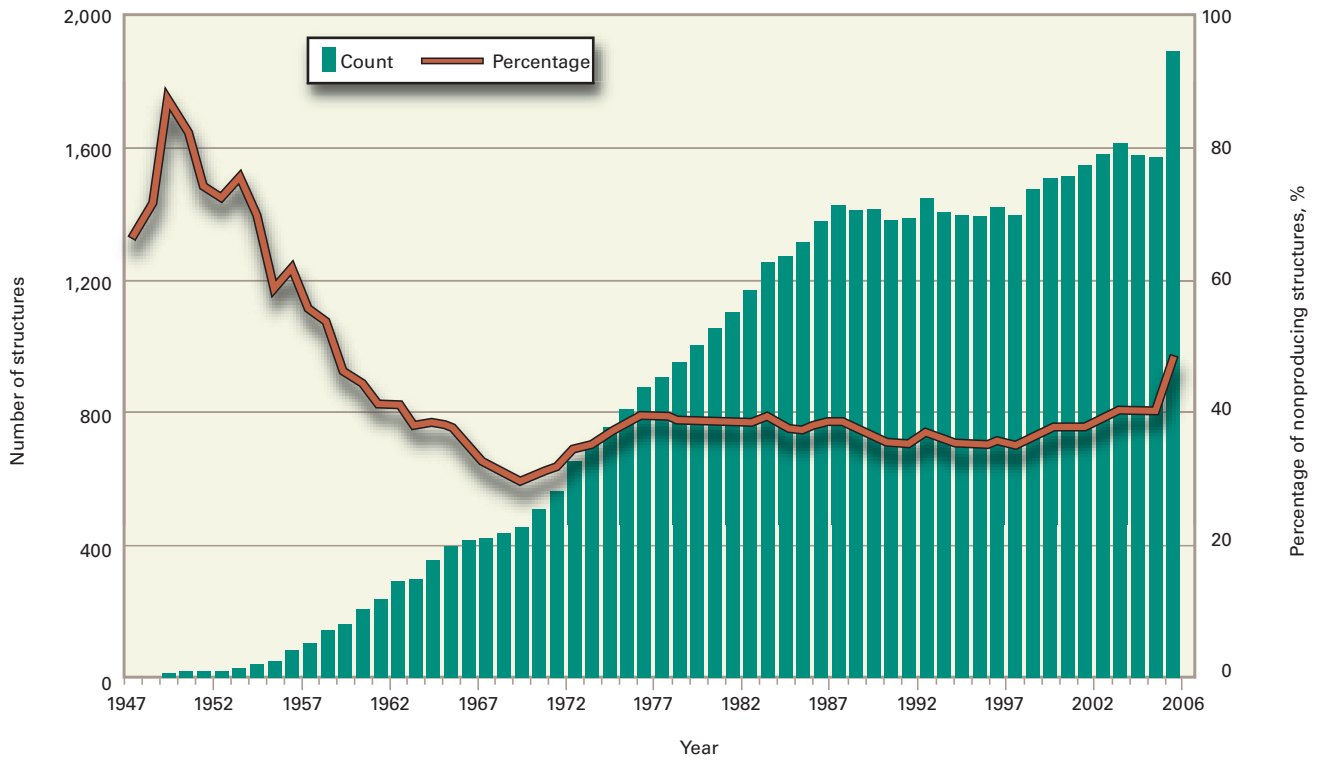
Gulf of Mexico producing structures

Fig. 5



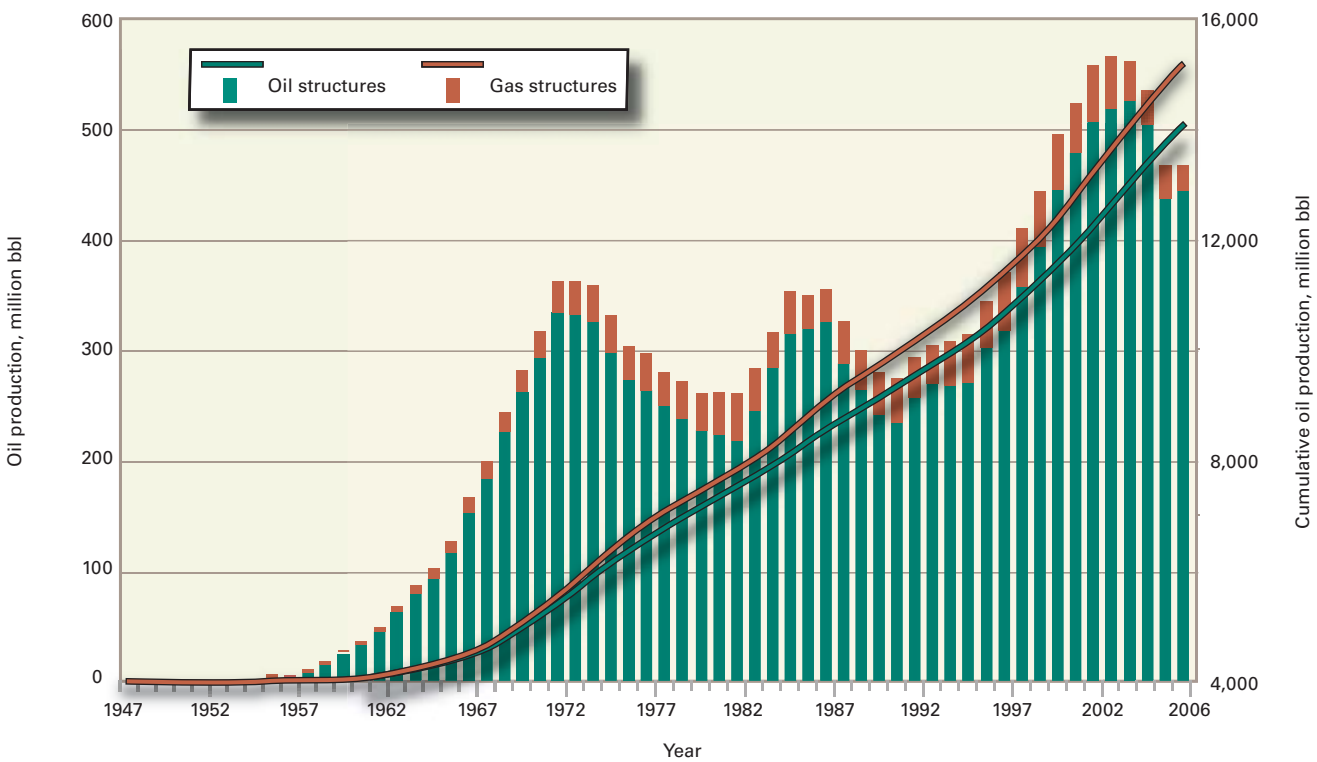
GULF NONPRODUCING STRUCTURES AND SHARE OF ACTIVE INVENTORY

Fig. 6



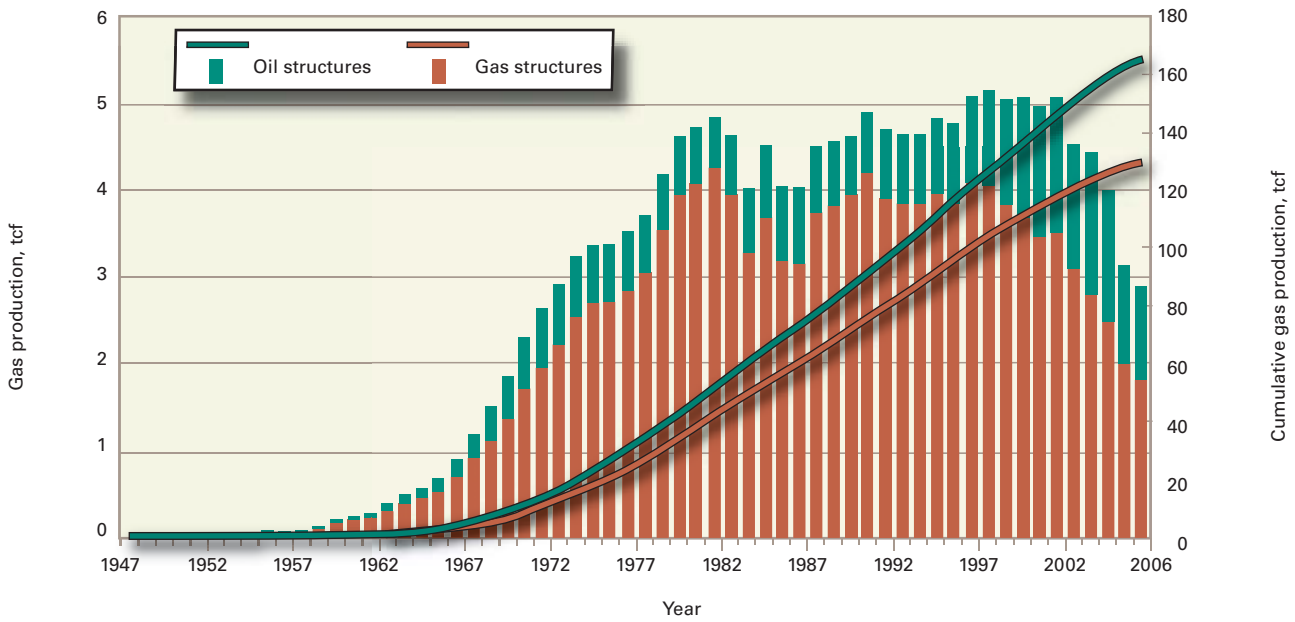
OIL PRODUCTION FROM GULF STRUCTURES

Fig. 7



GAS PRODUCTION FROM GULF STRUCTURES

Fig. 8



market conditions.

Offshore production tends to be more chaotic, and smoothly declining profiles near the end of production are not common, exacerbating the difficulty associated with forecasting abandonment. Mature structures produce from a small number of wells, and if a problem arises, it may not be economic to perform a workover.

The application of secondary and enhanced oil recovery techniques is more complex and subject to constraints such as space and weight restrictions and high transportation and operating costs not found onshore. Secondary and tertiary recovery techniques that are commonly used to extend the production life of onshore assets are usually not economic offshore.

Defining marginal production

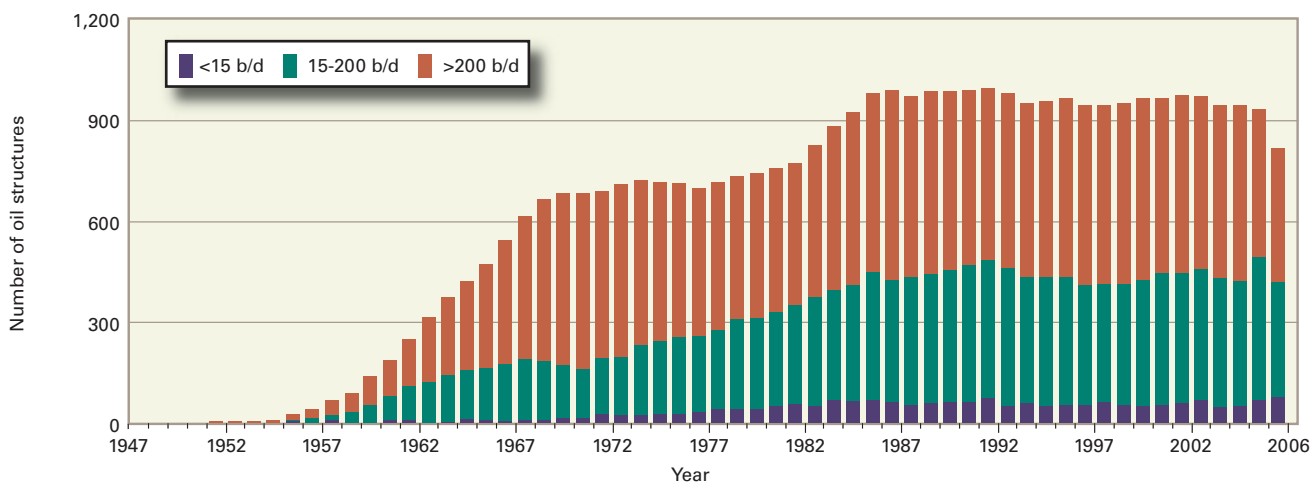
Production characteristics and profitability change during the life cycle of every structure.

Broadly speaking, the capital intensive expenditures associated with drilling wells and fabricating and installing infrastructure and equipment during the early years of a structure's life cycle are quickly replaced by revenue streams that recover the investment within a few years (Fig. 1).

There is nothing more profitable than an oil or gas well, and most structures start out highly profitable, but af-

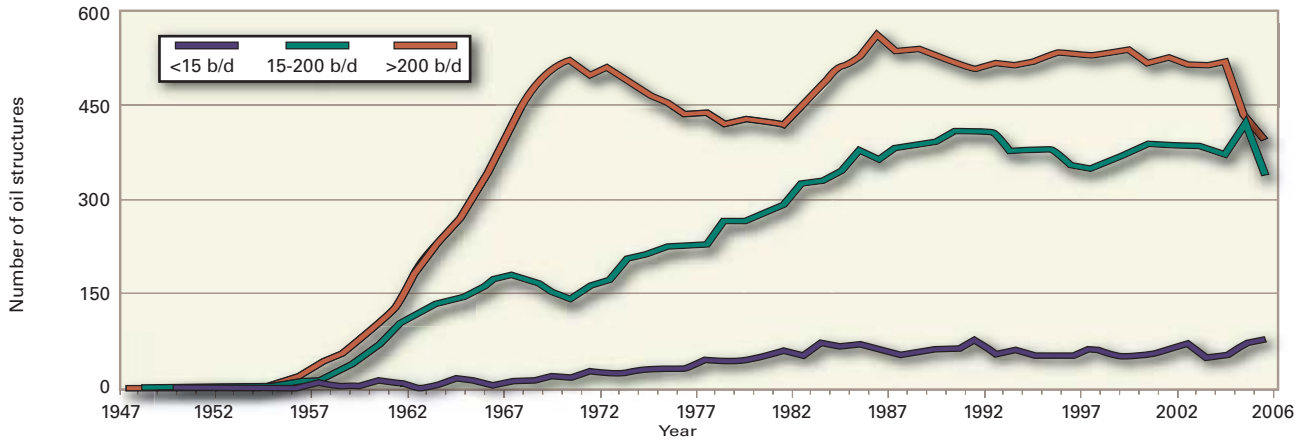
GULF OIL STRUCTURES BY DAILY OIL PRODUCTION

Fig. 9



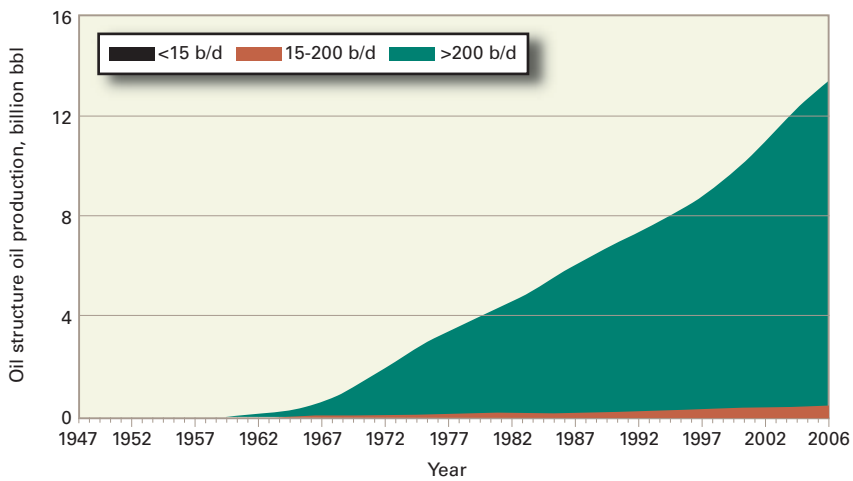
GULF OIL STRUCTURES BY DAILY OIL PRODUCTION

Fig. 10



CUMULATIVE OIL STRUCTURE PRODUCTION BY PRODUCING CATEGORY

Fig. 11

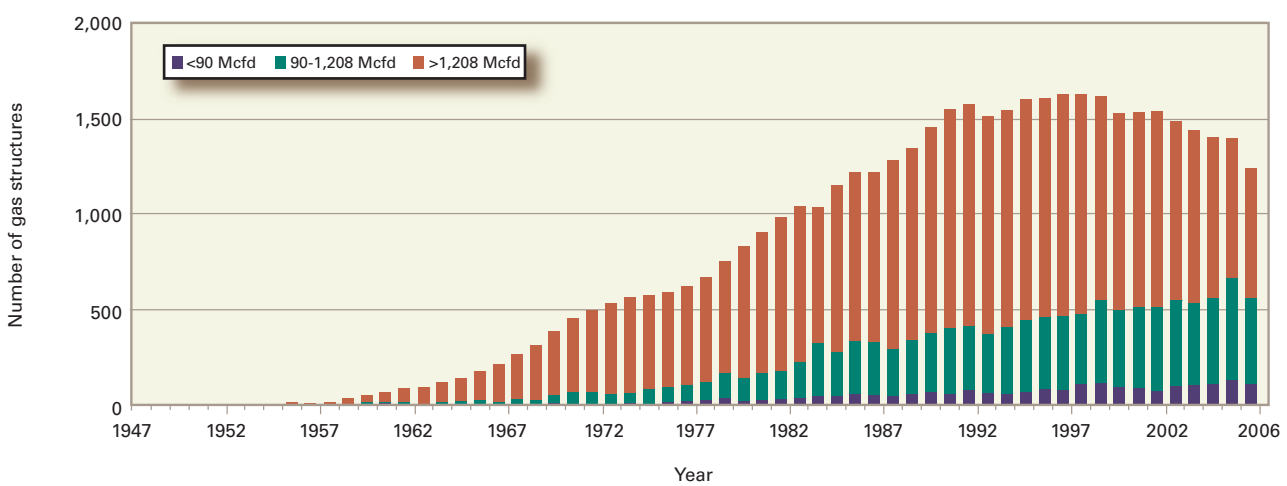


ter peak production, profitability tends to decline as costs increase and revenue decreases. At some point near the end of a structure's life, revenues approach operating cost and the asset becomes marginally profitable.

As reservoir pressure declines, the cash flow generating ability of the structure is replaced by a decreasing revenue stream, higher operating costs, fewer upside opportunities, and eventually, production that is worth less than the cost to operate and maintain the structure. At the end of the commercial life of a structure, the structure is abandoned and decommissioned according to regulatory guidelines.

GULF GAS STRUCTURES BY DAILY GAS PRODUCTION

Fig. 12



Marginal fields have different economics than large fields, require different recovery techniques, and are produced by smaller companies, usually proprietorships, partnerships, and limited liability companies. Production is still commercial (or "economic"), but the conditions under which a profit is generated tend to be more restricted.

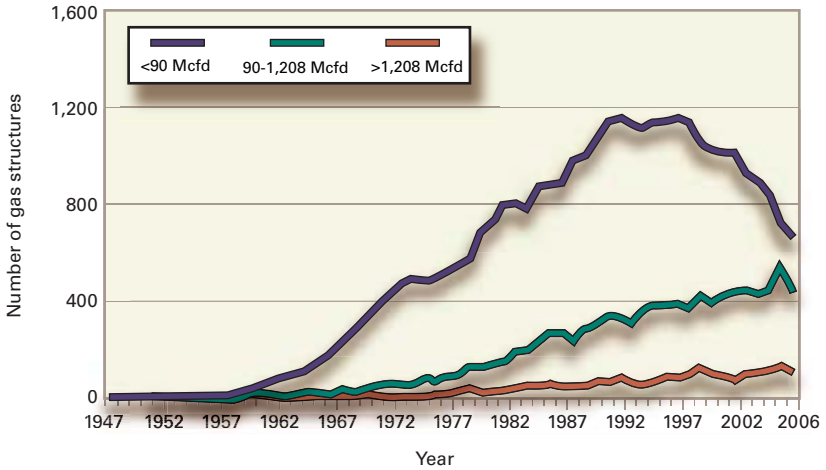
Marginal wells are often considered to operate on the lower edge of profitability, but no single definition of what constitutes a marginal well exists (Fig. 2). The dark arrow in Fig. 2 indicates the time period when structures are considered to enter their marginal phase.

When does production turn marginal? Ideally, a marginal well should be defined with respect to profitability, or when the marginal cost of operation equals the marginal revenue of production, but because cost is generally unapparent to an outside observer, the practical application of this definition has significant shortfalls.

The next best alternative is to apply a threshold to operationalize the definition of marginal production. Onshore and in state waters, state and federal regulations typically define marginal production based on a producing threshold of 10-15 b/d of oil and-or 60-90 Mcfd of gas. In federal waters, the MMS defines a marginal well as producing less than 90 b/d or 540 Mcfd.

Gulf gas structures by daily gas production

Fig. 13



Active structure count

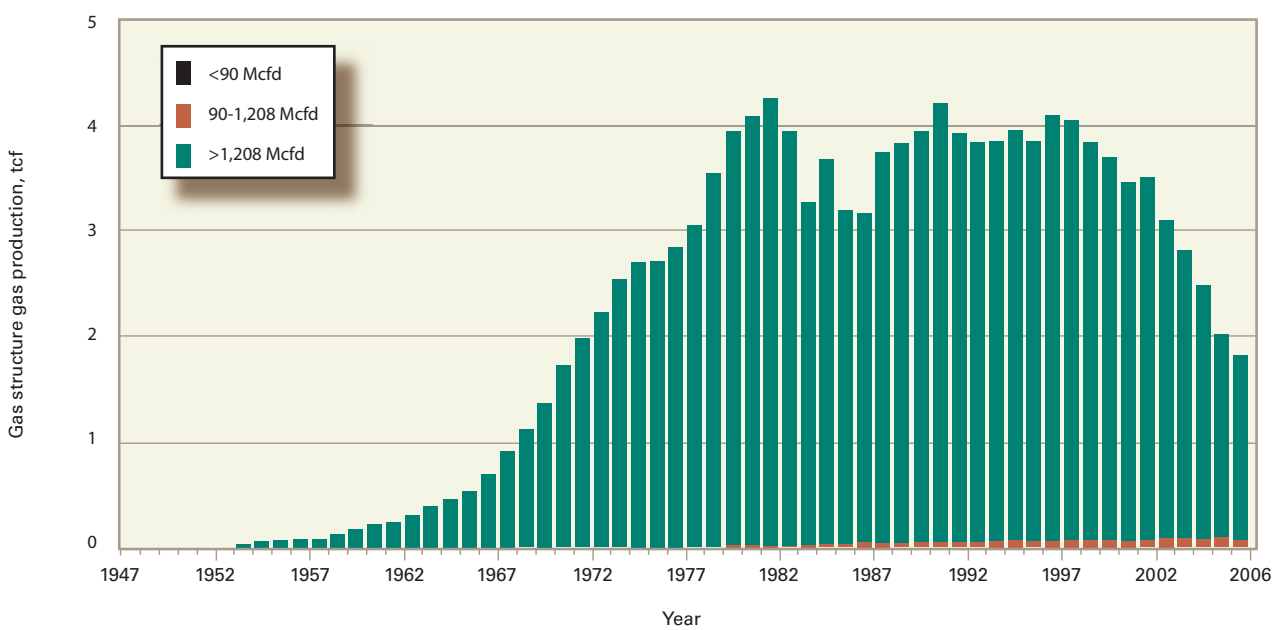
The number of active structures in the gulf is shown in Fig. 3.

Active structures represent the total number of structures that exist at any point in time and include both producing and nonproducing structures. In December 2006, there were 3,838 active structures: 2,324 fixed platforms, 380 well protectors, 1,091 caissons, and 43 "other" structures which includes deepwater floaters such as tension-leg platforms and spars.

The number of removals began to equal or exceed the number of installations in the early 1990s, and during this time, the inventory of active structures began to stabilize. The number

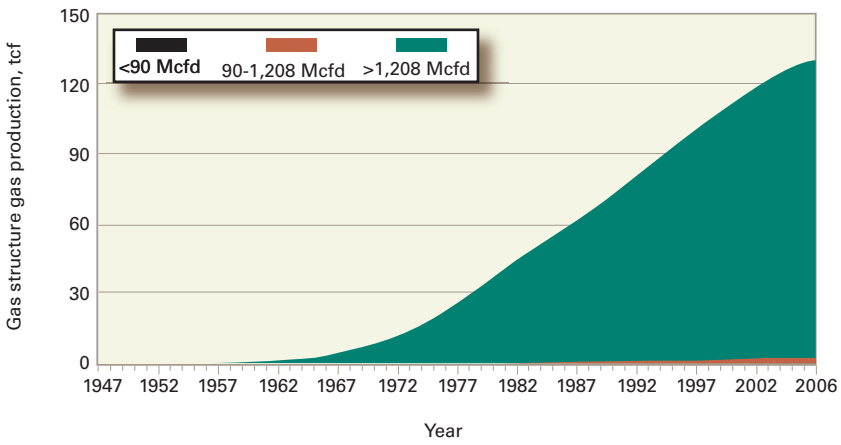
Cumulative gas structures by daily gas production

Fig. 14



CUMULATIVE GAS STRUCTURE GAS PRODUCTION BY PRODUCING CATEGORY

Fig. 15



of structures removed each year now exceeds the number of installations, and will likely continue in the future, as fewer new structures are installed on the shelf and a larger number of structures supporting marginal fields are abandoned.

Deepwater structures do not contribute materially to the structure count. The cumulative number of installed, removed, and active structures is shown in Fig. 4.

Producing structures

The number of structures producing hydrocarbons in the gulf is shown in Fig. 5 classified according to primary output.

A structure that produces any amount of oil or gas in the year of observation is said to be producing, and the producing gas-oil ratio (GOR) is used to classify structures as "oil" or "gas" producers. A structure with GOR <5,000 cu ft/bbl is labeled an oil structure and a gas structure corresponds to GOR >5,000 cu ft/bbl.

A producing structure may stop production for a period of time, perhaps due to hurricane damage or reservoir problems, temporarily reducing the producing structure count, only to reenter the inventory at a later time. Structures that are inactive for a few years, however, are unlikely to reenter the producing pool.

Gas structures began to outnumber oil structures in 1978 and currently represent about 65% of the total inventory of producing structures. The sharp decline in the number of producing structures in 2006 is due to the impact of the 2005 hurricane season: producing structures declined from 2,328 in 2005 to 2,017 in 2006. At the end of 2006, there were 813 oil producers and 1,204 gas producers in the gulf.

Nonproducing structures

The number of nonproducing structures is computed as the difference between the number of active and producing structures. Nonproducers include idle structures that once produced hydrocarbons as well as auxiliary structures that serve in a support role as a storage, compression, or metering facility and have never produced.

The number of nonproducing structures is shown in aggregate and as a percentage of the total number of active structures (Fig. 6). Interestingly, the number of idle structures has remained around 40% of the inventory for the last several decades. Before 1960, the percentage of nonproducers appears unusually high, but this may be due to reporting problems and-or other data integrity issues, or may simply be reflective of the immature state and small number of structures in the region at the time.

Production profiles

Oil production from oil structures and condensate production from gas structures is shown in Fig. 7 on an annual and cumulative basis.

Dry and associated gas production is shown in Fig. 8.

Oil structures produce the majority of liquid production with relatively small amounts of condensate contributed by gas structures. Oil structures produce a significant amount of associated gas, currently about a third of total gas production in the gulf.

Oil producers

The number of oil structures categorized by production group is shown in Fig. 9.

The number of oil structures across each production category has remained relatively stable over the past 2 decades.

The contribution to total oil production from low (<15 b/d), medium (15-200 b/d), and high producer (>200 b/d) structures is shown in Fig. 10. The 15 BOPD class contribute less than 0.1% total production on both an annual and cumulative basis, with the 15-200 b/d class contributing less than 3% (Fig. 11). Similar trends can be expected in the future.

Gas producers

The number of gas structures categorized according to daily gas production is shown in Figs. 12 and 13.

The contribution to total oil production from low (<90 Mcfd), medium (90-1,208 Mcfd), and high producer (>1,208 Mcfd) groups is shown in Fig. 14.

High producer groups constitute the majority of active gas structures and contribute more than 95% of total annual production and cumulative production. The contribution to cumulative gas production from low producers contributes less than 3%. While marginal producers account for about 4.6% of total active structures, their gas

production is less than 0.1% on both an annual and cumulative basis (Fig. 15).

Next: The author introduces the model framework used to identify marginal structures and the level of their future production. ✦

Reference

1. Kaiser, M.J., Yu, Y., and Pulsipher, A.G., "An assessment of marginal production in the Gulf of Mexico and lost production from early decommissioning," Center for Energy Studies, Louisiana State University, Baton Rouge, US Department of the Interior, Minerals Management Service, New Orleans, in review.

Eagle Ford shale McMullen joint venture forms

Activity further intensifies in the South Texas play for gas with condensate to varying degrees in Cretaceous Eagle Ford shale, according to developments reported in November.

Petrohawk Energy Corp. and Swift Energy Co. will jointly explore and develop 26,000 acres of Swift Energy's acreage in McMullen County, Tex., prospective in the Cretaceous Eagle Ford shale.

St. Mary Land & Exploration Co., Denver, drilled and completed three more horizontal wells on its 100% working interest acreage and progressed its joint venture with Anadarko Petroleum Corp.

And El Paso Corp. said it almost doubled its lease position to 112,000 net acres in the play, where it plans to maintain a one-rig program.

El Paso's first completion, a 4,000-ft lateral with a 16-stage frac in La Salle County, is still cleaning up with volumes increasing to the current flow rate of 6.1 MMcfe/d at 5,200 psi flowing tubing pressure.

Petrohawk-Swift Energy

Petrohawk will initially serve as operator of the 50-50 venture that covers leasehold interests in Swift Energy's AWP field 70 miles south of San Antonio beneath the gas-prone Olmos formation at 9,000-11,500 ft to the base of the Pearsall formation.

Petrohawk said it believes Swift Energy's acreage is in a geologically ideal depositional location and contiguous to Petrohawk's rapidly developing program in Hawkville field.

Swift Energy has sizable acreage outside the joint venture and plans to drill a horizontal test well before yearend.

St. Mary status

St. Mary's Galvan Ranch-1H, with a 5,005-ft effective lateral and 17-stage completion, averaged 8 MMcfe/d after 7 days of sales. It is the farthest south well to date and has 1,000 btu/scf gas with essentially no condensate.

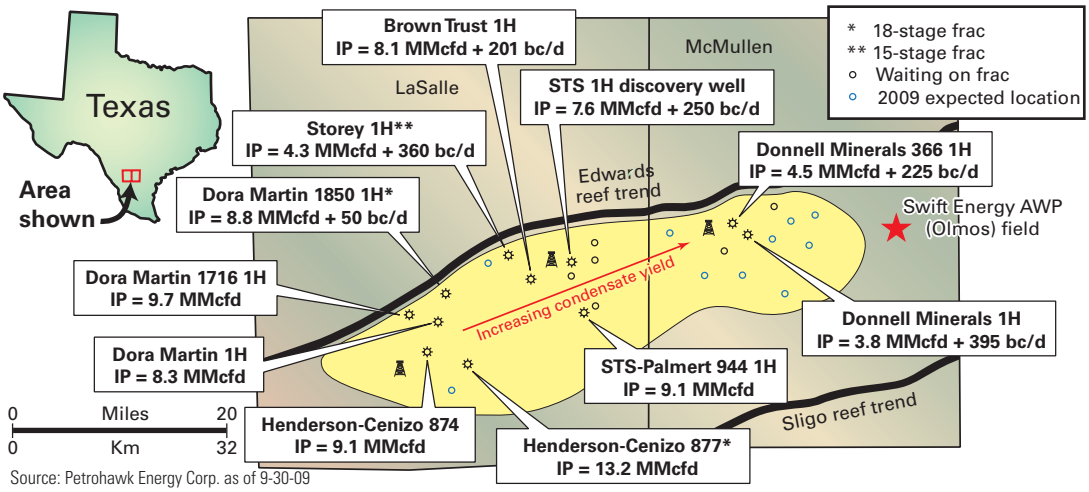
Briscoe Apache Ranch-1H, with a 4,000-ft lateral and 14-stage completion, averaged 7.1 MMcfe/d and has a richer gas stream at 1,200 btu/scf.

Galvan Ranch 4H, with a 5,000-ft lateral and 15-stage completion, flowed at 7 MMcfe/d with little condensate at 3,600 psi flowing wellhead pressure constrained by temporary pipeline limitations. In joint venture acreage north of the company's 100% working interest position, St. Mary took over from TXCO Resources Co. as the drilling operator earlier this year and drilled and completed the remaining three earn-in wells in Phase II. Consistent with St. Mary's prior statements, it is clear from the initial flowback results from these wells that this part of the play will have high condensate yields. Anadarko is installing more sales infrastructure to facilitate further testing.

St. Mary has leased or optioned 225,000 net acres in the Eagle Ford shale, with roughly 159,000 net acres of operated, high working interest acreage and 66,000 net acres in the joint venture.

Kinder Morgan Energy Partners LP and Copano Energy LLC also plan to develop gathering, transportation, and processing services in the play (OGJ Online, Nov. 20, 2009). ✦

EAGLE FORD SHALE DRILLING RESULTS



Source: Petrohawk Energy Corp. as of 9-30-09

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More CO_2-EOR projects likely as new CO_2 supply sources become available

Guntis Moritis
Production Editor

The number of US projects injecting carbon dioxide for enhancing oil recovery likely will increase as new CO_2 supplies become available.

For example, in states on the US Gulf Coast, Denbury Resources Inc. continues to add pipelines for distributing CO_2 to new fields.

Companies also have slated new projects for the northern portion of the Rocky Mountains and the Permian basin of West Texas and New Mexico. These projects will use new CO_2 sources.

In Canada, Saskatchewan has two large ongoing projects that obtain CO_2 from a coal gasification plant in North Dakota.

CO_2 EOR

In the US, CO_2 injection has accounted for recovering about 1.5 billion bbl of oil and US CO_2 sales for EOR reached an estimated 3 bcfd in 2008 (Fig. 1).[1]

CO_2 source fields provide most of the gas injected in North American EOR projects. About 83% comes from source fields, 10.6% from natural gas plants, 1.4% from fertilizer plants, 4.9% from coal gas synfuels, 0.1% from ethylene production.[1]

Fig. 2 shows current US CO_2 sources and pipelines.

The amount of US remaining oil in place is large. A 2008 report said that, of the estimated 595.7 billion bbl of oil in place, only 195.7 billion bbl will be recovered with conventional means, leaving 400 billion bbl stranded in the ground (table).[2] Of this, the report estimated that 87.1 billion bbl could be technically recovered with CO_2 injection.

Oil & Gas Journal's last EOR survey (Apr. 21, 2008, p. 47) listed 100 ongoing CO_2 miscible and 5 CO_2 immiscible EOR projects. The enhanced oil production from these projects at the beginning of 2008 was 250,000 b/d. The survey also showed 12 new CO_2-EOR projects would start during 2008-09.

An April 2010 OGJ article will update the EOR survey.

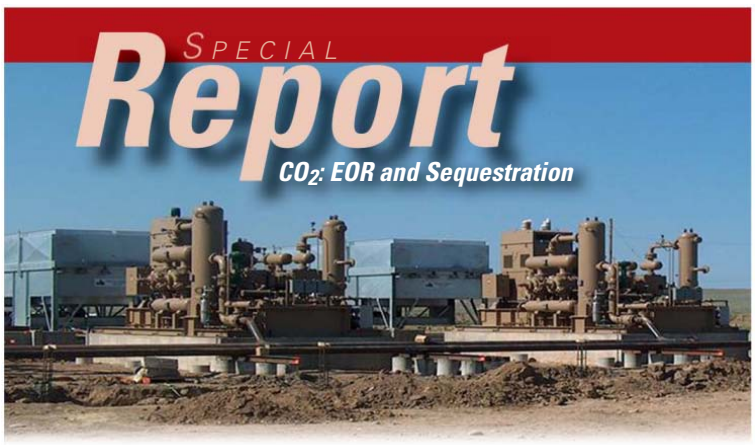
Most of the US CO_2-EOR projects are in the US Gulf Coast, Rocky Mountains, and the Permian basin. In Michigan, Core Energy LLC operates several CO_2-EOR projects that obtain CO_2 from an Antrim gas processing plant.

US Gulf Coast

In the Gulf Coast, Denbury continues its phased expansion of CO_2 projects (Fig. 3).

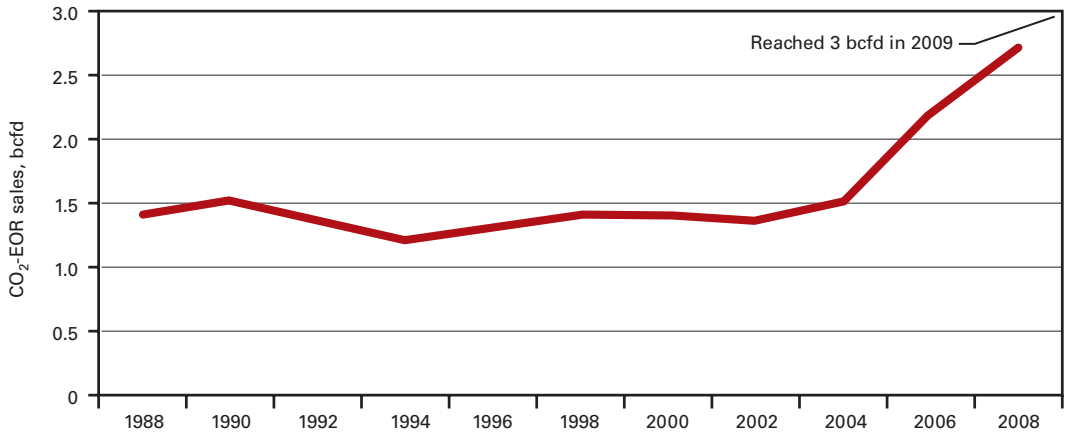
During third-quarter 2009, the company reported production of 24,347 bo/d from its CO_2 projects, including an 829 bo/d production response from CO_2 injection at Heidelberg field in Mississippi. Heidelberg is one of the fields in the company's Phase 2 expansion.

Denbury also reported production increases during third quarter as



US CO_2-EOR SALES

Fig. 1



Source: Reference 1

compared with the previous quarter, as follows:

- Tinsley (3,558 bo/d, a 5% increase).
- Soso (2,813 bo/d, a 9% increase).
- Lockhart Crossing (882 bo/d, a 26% increase).
- Cranfield (572 bo/d, a 69% increase).

From its Gulf Coast CO_2 EOR operations, Denbury expects production to increase to 55,000-65,000 bo/d by 2016 (Fig. 4).

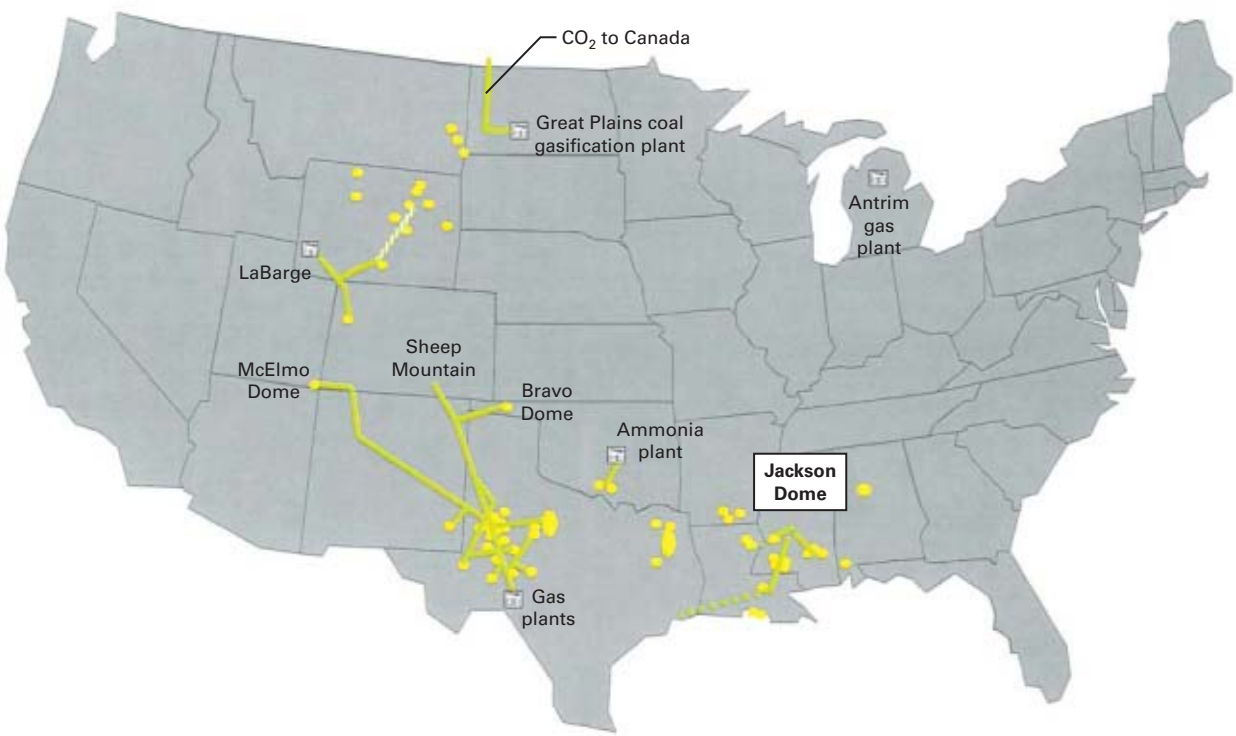
Recently the company completed the Delta pipeline and commenced CO_2 injection at Delhi field in mid-November. It expects first tertiary oil production from Delhi in mid-2010

Green is another pipeline it has under construction. Denbury expects completion of the pipeline to Oyster Bayou field in Texas during first-quarter 2010 and the pipeline reaching Hastings field by late 2010. It plans to transport both natural CO_2 and anthropogenic CO_2 in the 320 mile, 24-in. pipeline from Donaldsonville, La., to Hastings field.

Denbury has purchase contracts with several planned industrial plants that will have CO_2 available, if built, after 2013. These plants are in Louisiana, Mississippi, Kentucky, Illinois, and Indiana and could provide 1.6-2.1 bcfd

CO_2 SOURCES, PIPELINES

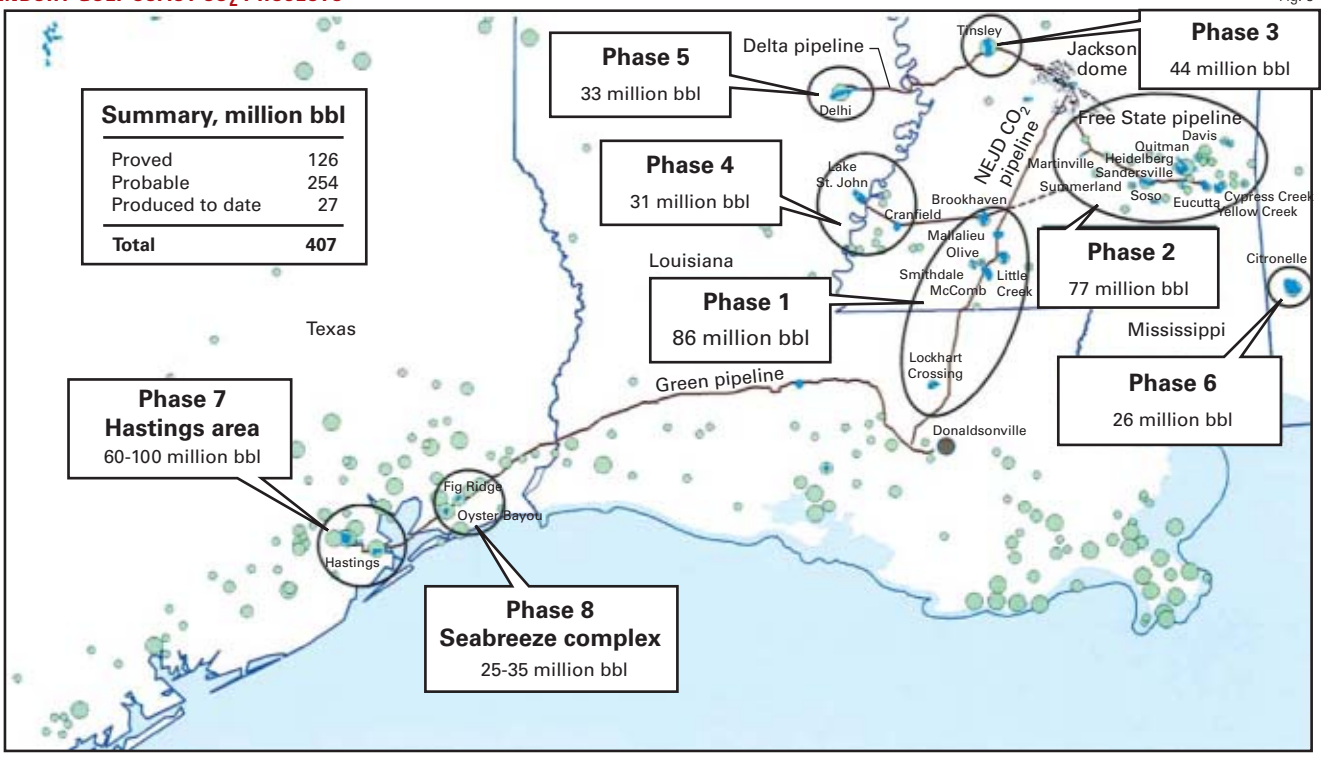
Fig. 2



Source: Denbury Resources, Inc.

DENBURY GULF COAST CO_2 PROJECTS

Fig. 3



Note: Each phase reserves are proved plus probable tertiary oil reserves as of Dec. 31, 2008, including past production.
Source: Denbury Resources Inc.

of CO_2, according to Denbury.

The company plans to begin CO_2 injections at Oyster Bayou in mid-2010 with an initial production response expected in early 2011.

Denbury notes that its CO_2-EOR operating costs during second-quarter 2009 were $20.86/boe, broken down as:

- $3.68/boe for CO_2.
- $5.72/boe for power and fuel.
- $3.34/boe for labor and overhead.
- $2.00/boe for equipment rental.
- $1.36/boe for chemicals.
- $3.05/boe for workovers.
- $1.71/boe for miscellaneous.

Denbury also will continue to prove up Jackson Dome's probable CO_2 reserves in 2010. It plans to drill the first of three delineation wells early in 2010. Its CO_2 reserves estimate for Jackson Dome is 5.6 tcf proved, 3 tcf probable, and 2 tcf possible (Fig. 5).

Potential Midwest and Gulf Coast anthropogenic sources could increase available Gulf Coast CO_2 supplies to more than 3 bcfd by 2016.[1]

Except for some sales to industrial consumers, Denbury uses all the CO_2 produced from the Jackson Dome for its own projects.

Rocky Mountains

Since 1986, most CO_2 for EOR projects in the northern Rocky Mountains has come from the ExxonMobil Corp.-operated Shute Creek gas processing plant in southwestern Wyoming.

Earlier this year (OGJ Online, June 29), Encore Acquisition Co. announced plans to purchase 50 MMcfd of CO_2 for its Bell Creek EOR project in southeastern Montana from the ConocoPhillips-operated Lost Cabin gas plant in Fremont County, Wyo.

The project involves building compression adjacent to the plant and installing a 206-mile pipeline to transport

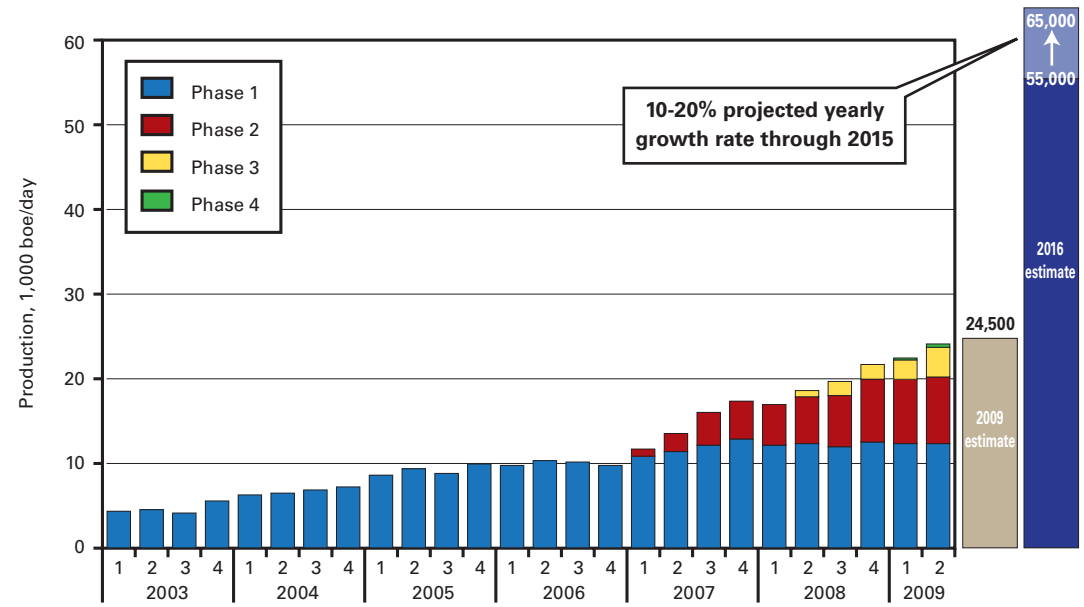
US CO_2 TECHNICALLY RECOVERABLE RESERVES

	OOIP	Conventionally recoverable	Recoverable with CO_2-EOR
	Billion bbl		
1. Alaska	67.3	22.3	12.4
2. California	83.3	26.0	6.3
3. Gulf Coast (Ala., Fla., Miss. Ala.)	44.4	16.9	7.0
4. Midcontinent (Okla., Ark., Kan., Neb.)	89.6	89.6	10.7
5. Illinois, Michigan	17.8	6.3	1.2
6. Permian (West Tex., NM)	95.4	33.7	17.8
7. Rockies (Colo., Utah, Wyo.)	33.6	11.0	4.2
8. Texas (east-central)	109.0	35.4	17.6
9. Williston (Mont., ND, SD)	13.2	3.8	2.5
10. Louisiana offshore	28.1	12.4	5.8
11. Appalachia (W.Va., Ohio, Ky., Pa.)	14.0	3.9	1.6
Total	**595.7**	**195.7**	**87.1**

Source: Reference 2

DENBURY QUARTERLY TERTIARY OIL PRODUCTION

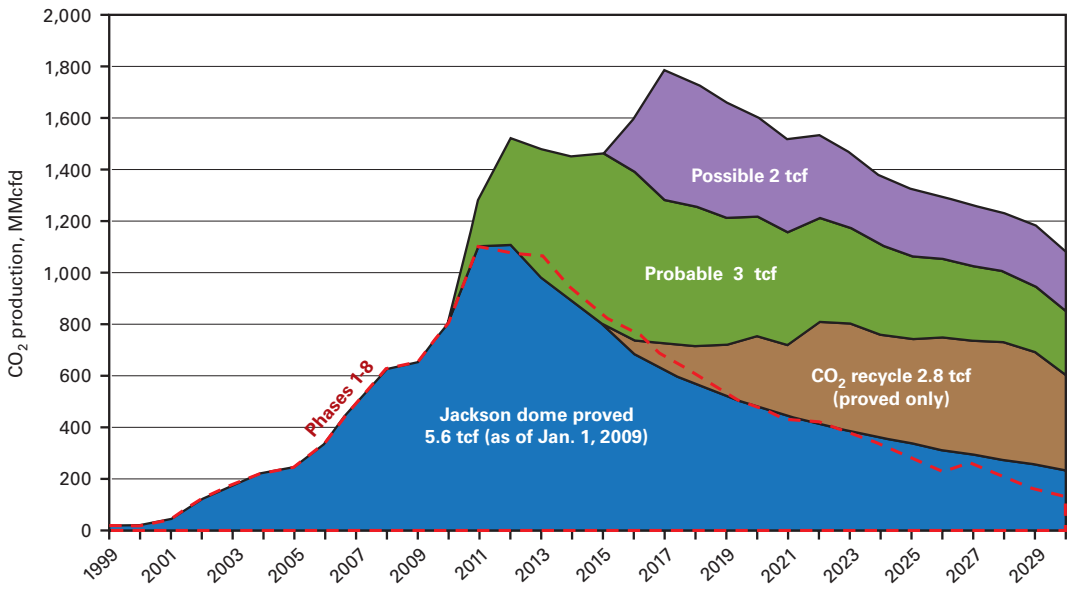
Fig. 4



Source: Denbury Resources Inc.

POTENTIAL JACKSON DOME CO_2 SUPPLY

Fig. 5



Source: Denbury Resources Inc.

compressed CO_2 to Bell Creek. At Bell Creek, the company would reactivate 275 wells and drill as many as 75 more wells to establish a five-spot injection pattern.

Encore estimated the production response from 100% utilization of the available CO_2 at more than 6,500 b/d by 2015, with output remaining at that level for 10 years.

Since that announcement, Denbury signed a merger agreement with Encore (OGJ, Nov. 9, 2009, p. 26).

Estimated recoverable oil from Encore's potential CO_2-EOR projects are 30 million bbl from Bell Creek, 37 million bbl from Elk basin, 61 million bbl from South Pine, and 136 million bbl from other fields in the Cedar Creek anticline.

The Cedar Creek anticline is within 120 miles of Bell Creek. Shell Oil, the original South Pine operator, conducted a pilot CO_2 flood in the field in the 1980s.

Two potential new sources for CO_2 in Wyoming are from a proposed underground coal-gasification project in the Powder River basin and a coal gasification and liquefaction project near Medicine Bow, Wyo.

Linc Energy Ltd., Australia, plans to start a UCG pilot by mid-2011 from acreage it purchased from GasTech Inc. in the Powder River basin of northwest Wyoming.

Another project is the Medicine Bow Fuel & Power LLC facility that includes a coal mine adjacent to a coal-to-liquids plant, with the first phase slated to produce about 21,000 b/d of ultralow-sulfur diesel fuel.

These two projects could supply 335 MMcfd of CO_2 for EOR in 2013.[3]

Another CO_2 source that will become available in 2010 is completion

of a $72 million expansion at ExxonMobil's Shute Creek gas processing plant. The expansion includes installation of 23,000 hp of CO_2 compression for increasing CO_2 sales by 110 MMcfd from the current 230 MMcfd.[4 5]

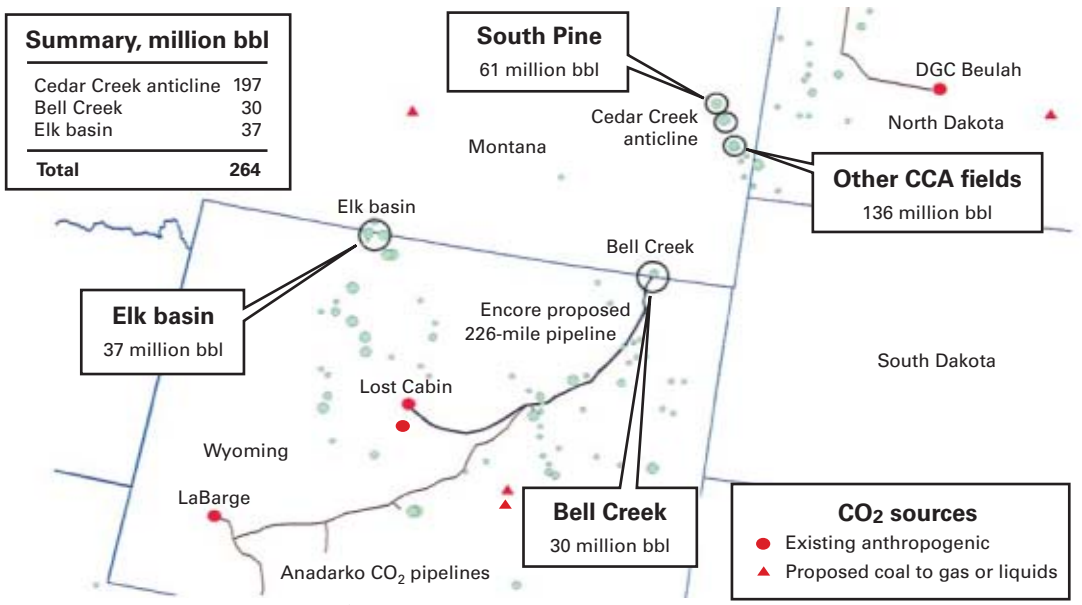
The Shute Creek plant in Lincoln County, Wyo., has a 700-MMcfd gas processing capacity and receives gas from LaBarge field in Sublette County, Wyo. Composition of the gas from La Barge is 66% CO_2, 21% methane, 7% nitrogen, 5% hydrogen sulfide, and 0.6% helium.

The Shute Creek plant, the largest gas-sweetening plant in the world, produces 25-30% of the world's supply of helium, about 4 MMcfd, and injects the most acid gas consisting of 35 MMcfd of hydrogen sulfide and 25 MMcfd of CO_2.[4 5]

La Barge is also the site of a $100 million pilot for demonstrating ExxonMobil's controlled freeze zone single-step process for CO_2 separation. The company plans to start a pilot during 2010 and expects it to be a lower cost process that may make carbon capture and sequestration a more practical option for CO_2 separated from natural gas.[4 5]

Encore CO_2 projects

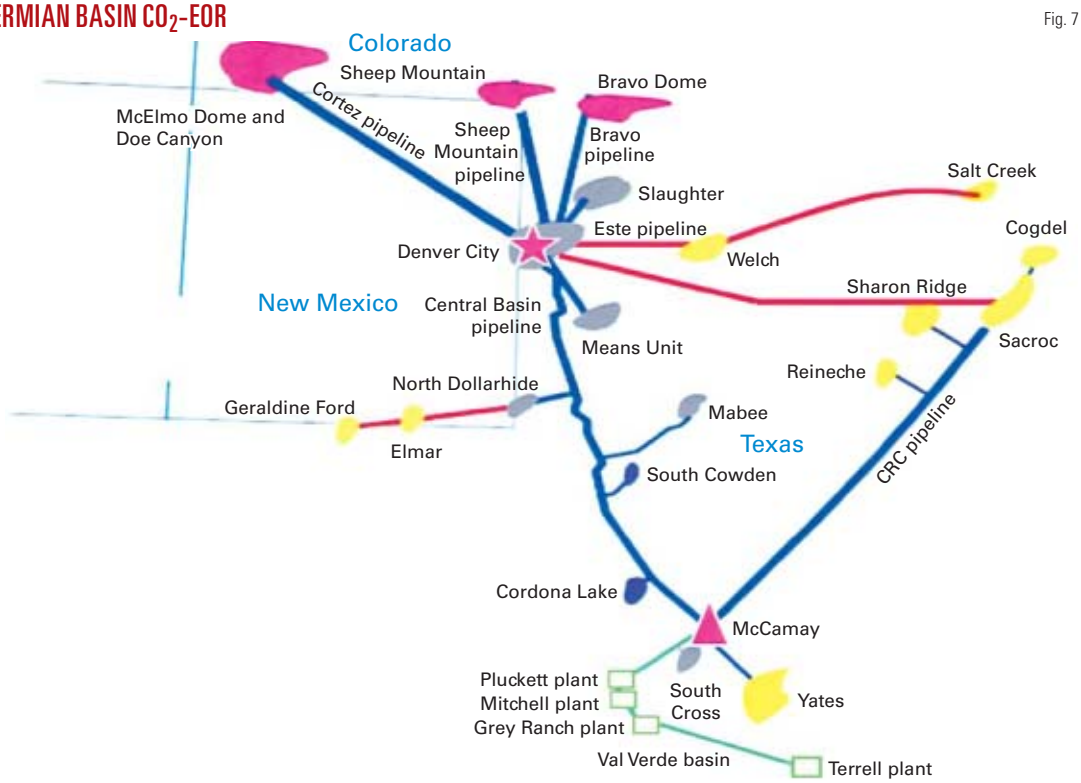
Fig. 6



Note: Probable and possible reserves estimates as of Dec. 31, 2008.
Source: Denbury Resources Inc.

Permian basin CO_2-EOR

Fig. 7

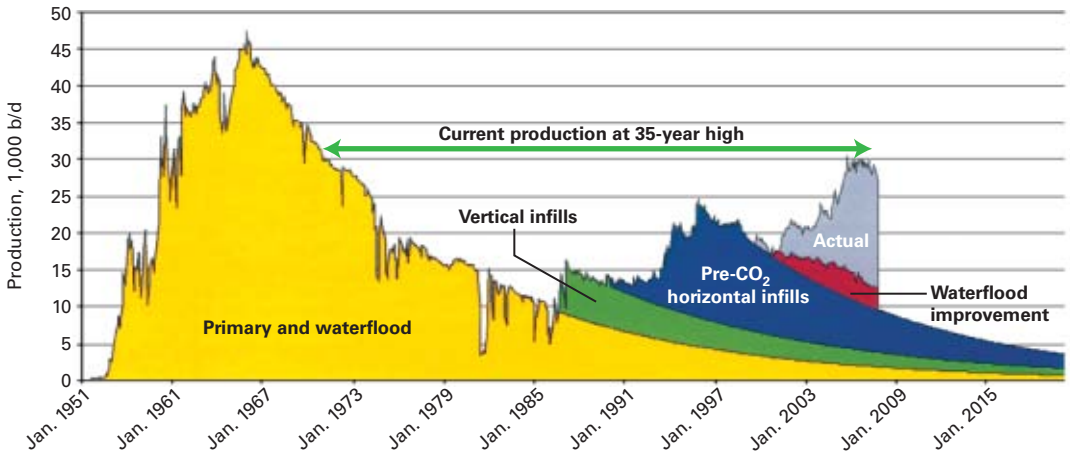


Note: The figure does not include all of the CO_2-EOR projects and pipelines in the basin.
Source: Reference 1

Currently ExxonMobil sells CO_2 to five EOR projects in Wyoming and one in Colorado. The Wyoming projects are

WEYBURN UNIT PRODUCTION

Fig. 8



Source: Reference 1

the Anadarko Petroleum Corp.-operated Patrick Draw (Monell Unit) and Salt Creek fields, Devon Energy Corp.-operated Beaver Creek field, and Merit Energy Co.-operated Lost Soldier and Wertz fields.

In Colorado, Chevron Corp. operates an EOR project in Rangely field that receives CO_2 from Shute Creek.

Wyoming has many potential CO_2-EOR projects if enough CO_2 became available. One estimate is that EOR projects in Wyoming could recover about 418 million bbl of oil with the injection of about 2.68 tcf of CO_2.[6]

Permian basin

Fig. 7 shows the main CO_2 sources and CO_2-EOR fields in the Permian basin. Steve Melzer, a consultant in Midland, Tex., told OGJ that lack of additional CO_2 has limited expansion and start of new CO_2 injection projects in the basin.

The basin produces about 180,000 bo/d because of CO_2 EOR.

Currently fields in the Permian basin receive about 1.6-1.8 bcfd of CO_2. Kinder Morgan CO_2 Co. operates McElmo Dome and Doe Canyon source fields in Colorado that have a capacity to produce about 1.3 bcfd, after the company finished a 200-MMcfd capacity expansion in early 2009.

Sheep Mountain source field in Colorado, operated by Occidental Petroleum Corp. (Oxy), is nearing depletion and delivers about 40 MMcfd to the basin.

Work continues in expanding CO_2 production capacity at Bravo Dome in New Mexico, operated by Oxy. The field has a capacity to deliver 250 MMcfd to the basin.

Hess Corp. in the last year has developed West Bravo field to deliver about 110 MMcfd of CO_2 for expanding injection in the residual oil transition zone in the San Andres formation. The zone lies below the original oil-water contact in Seminole field and now has a higher oil saturation than the depleted zones above.

Melzer noted that several companies are looking at expanding CO_2 injection to residual oil transition zones in several of the main CO_2-EOR fields in the Permian basin.

Another source of CO_2 is the gas plants in the Val Verde basin that deliver about 80 MMcfd of CO_2 to Permian basin projects.

Under construction in Pecos County, Tex., is the $1.6 billion Century gas processing plant. SandRidge Energy Inc., under an agreement with Oxy, will operate the CO_2 extraction plant and associated CO_2 compression and pipeline facilities. SandRidge will retain the separated methane, while Oxy will take the removed CO_2. SandRidge expects completion of the first phase of the plant in 2010 and completion of the all three phases in 2011.

Oxy is the largest operator of CO_2-EOR oil projects with 28 active projects in the Permian basin.

One company starting a new CO_2-EOR pilot in the Permian basin is Legado Resources LLC in Goldsmith field, Ector County, Tex.

Another new project is in Katz field near Knox City, Tex.

Charles Fox, vice-president of Kinder Morgan CO_2, told OGJ that Kinder Morgan has under construction a $36 million, 91 mile, 10-in. pipeline to transport CO_2 from its operated Sacroc CO_2-EOR project to Katz field.

Fox said the pipeline will have an initial 65-MMcfd capacity but that, if companies along the line show interest, Kinder Morgan could increase capacity to 200 MMcfd.

Kinder Morgan plans to invest $145 million in the Katz CO_2-EOR project to increase its production to a 7,000 bo/d peak in 2015 from the current 600 bo/d, Fox said. He added that the project involves drilling 88 wells, which includes 45 CO_2 injection wells, during the next 4-5 years. The company expects to start CO_2 injection in late 2010 or early 2011.

Kinder Morgan also will be adding CO_2 injection patterns to its CO_2-EOR project in Sacroc. Fox said the goal is to keep production from Sacroc at a steady 30,000 bo/d.

The company also is continuing its immiscible CO_2 pressure-maintenance project in Yates field. Fox said one of the main activities in the field is the drilling of 1,500-ft horizontal drain

holes from existing wellbores. He said Kinder Morgan drilled about 60 drain holes in 2009 and plans to drill about the same number in 2010. Yates produces about 27,000 bo/d through gravity drainage.

Fox noted that CO_2 may become more available in the Permian basin towards yearend 2010 and that this should result in several companies announcing new projects in the basin.

Canada

The Weyburn CO_2 miscible flood in Saskatchewan remains the main CO_2 flood in Canada, producing more than 18,000 b/d of incremental oil. Weyburn obtains its CO_2 from the Dakota Gasification Synfuels plant, Beulah, ND. Current production from the field, with CO_2 EOR, is at a 35-year high (Fig. 8). Cenovus Energy Inc., a spin-off company of EnCana Corp., now operates Weyburn.

Apache Canada Ltd. in 2005 started a full-field CO_2 project in Midale field in Saskatchewan, also with CO_2 purchased the from Dakota gasification plant. In a Mar. 6, 2009, update, Apache estimated that CO_2-EOR adds to the field 46 million bbl of proven recoverable oil reserves and 22 million bbl of possible oil reserves. ✦

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REFINERY GASES—2

Oxygen assists in process intensification, hikes flexibility

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Part 1 of this series of three articles dealt with the uses hydrogen and nitrogen found in oil refineries. Some of these uses have been around for a long time and are well known; others are newer, dictated by new and more stringent regulations or by rising energy prices (OGJ, Nov. 23, 2009, p. 50).

This second article deals with the uses of oxygen in oil refineries. All these uses come together under "Process Intensification," which also includes achieving higher flexibility. This becomes increasingly important as the worldwide consumption of fuel is still rising while only few new refineries are being built. Therefore the load on existing refineries rises and spare capacities shrink.

In this situation refiners must minimize new investment for adaptation to the changed economic environment and maximize output from existing equipment. For that goal, process intensification by use of oxygen is an option that includes mature technologies that are cheap to install and easy to operate safely.

Use of oxygen

Hydrogen has always been used in refineries; but oxygen not so much. This is changing for three main reasons:

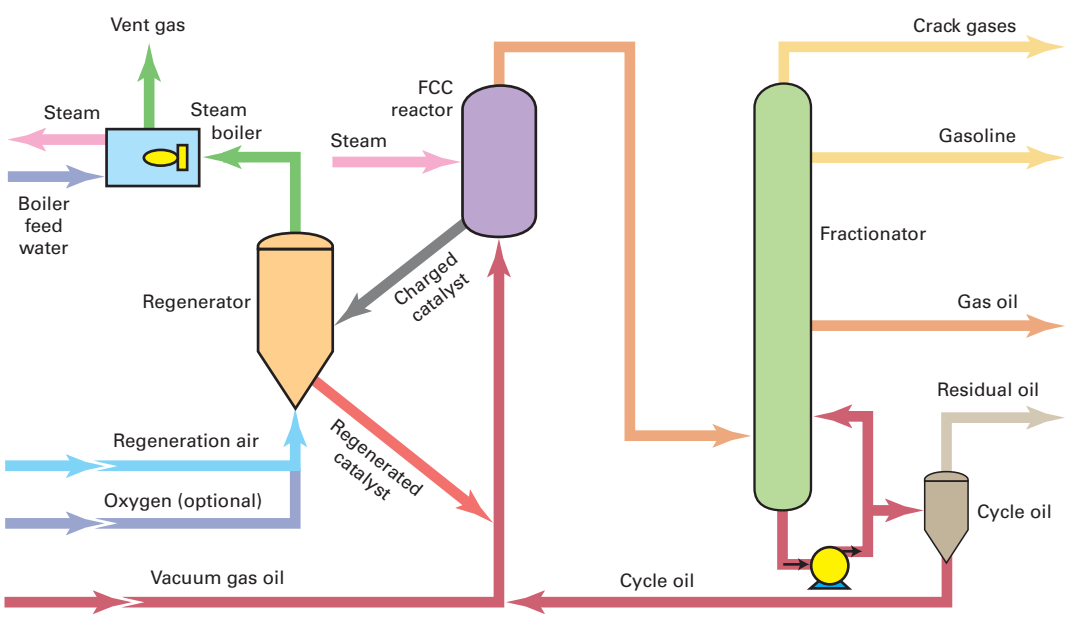
1. Refiners are reducing excess capacities for better economy. New environmental laws, however, have forced some refineries to add capacities. That is particularly true, for instance, for fluid catalytic cracking to utilize heavy feed oils, and for Claus plants, which receive more sulfur and substantially more ammonia from hydrotreaters. Similarly, the capacity of the waste water treatment plant can be increased by using oxygen.

These applications fall under "process intensification."

2. The higher volatility of crude oil and product prices forces greater flexibility on refiners. Oxygen enrichment allows equipment to be operated in a wider load range. Air-blown Claus plants, for example, can be typically

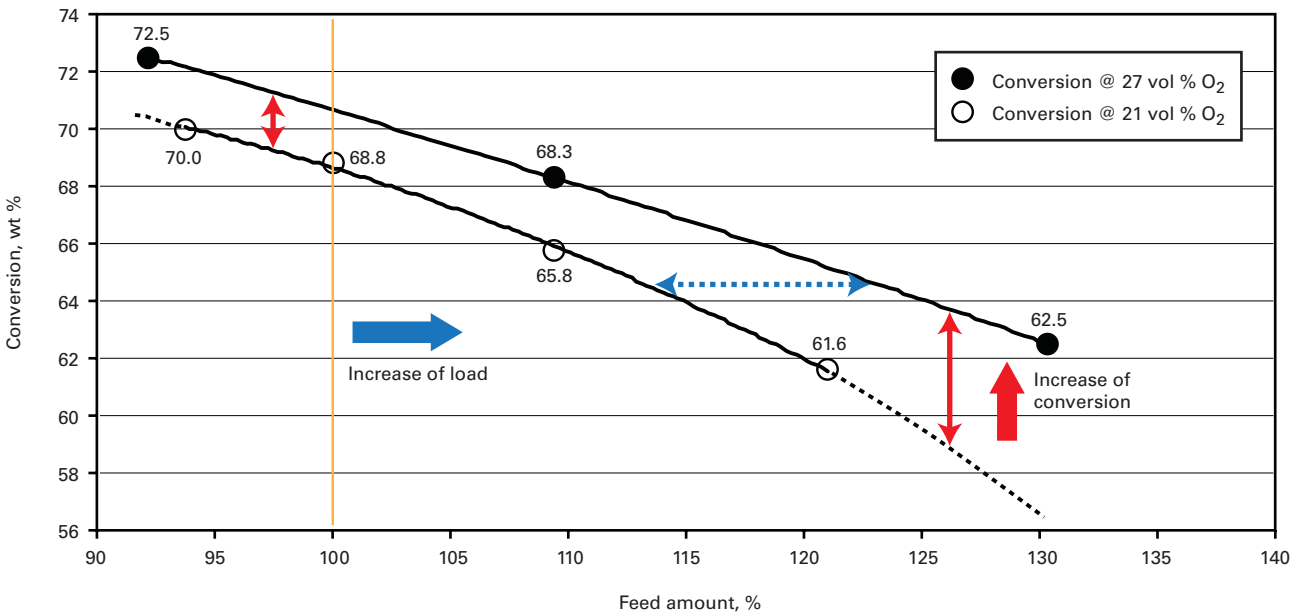
FLUID CATALYTIC CRACKER PLANT

Fig. 1



PILOT PLANT STUDY RESULTS

Fig. 2



operated within a load range of 30-100%. Even with low-level oxygen enrichment, these plants can tolerate 30-135% load.

3. Oxygen gasification of residues allows full conversion of even the last drop of crude oil to valuable products. This broadens the economic base of a refinery and makes it more flexible and efficient.

Gasification gas can be used for many purposes, especially for hydrogen recovery; as a synthesis gas, particularly in C_1 chemistry; and as a fuel in an integrated gasification combined cycle power plant. More recently synthesis gas from a gasifier may also be used for gas-to-liquids processes, which make synthetic, ultralow sulfur fuel.

The following discusses the uses of oxygen in various refinery processes.

FCCU

Fluid catalytic cracking converts heavy hydrocarbons into light ones.[4] A refinery operator can use it to shift products between heavy and light, making more diesel fuel or more gasoline, for example. Vacuum gas oil is used primarily as feed to an FCCU but the FCCU can also process residues, thus increasing product yield as well as contributing to useful disposal of it.

At 450° to 650° C., the FCC reactor breaks down hydrocarbons into hydrocarbons with shorter chains. The reaction produces coke as a by-product and deposits it on the catalyst. The coke is removed by burning at 550° to 750° C. in regeneration. Then the regenerated catalyst can be returned to the reactor.

Fig. 1 shows an FCC plant.

Developments with respect to clean fuels and fewer emissions also affect the FCC process:

- FCC regeneration is one of the major sources of sulfur dioxide emissions in a refinery. They can be eliminated either by improving cleanup of waste gas from the FCCU or by reducing the sulfur content of feed to the unit.

In waste-gas cleanup, which usually uses sodium hydroxide, sulfur dioxide is bound to sodium hydroxide and then flows into the waste water. Emissions, in other words, move from the atmosphere to the waste water.

This may be acceptable under regulations, but it is certainly not an environmentally favorable disposal. More preferable is severe hydrogenation of the FCC feeds in the hydrotreaters and recovery of the sulfur as a product. Then the vacuum gas oil, with distinctly lower sulfur content, produces fewer emissions from the FCC regenerator.

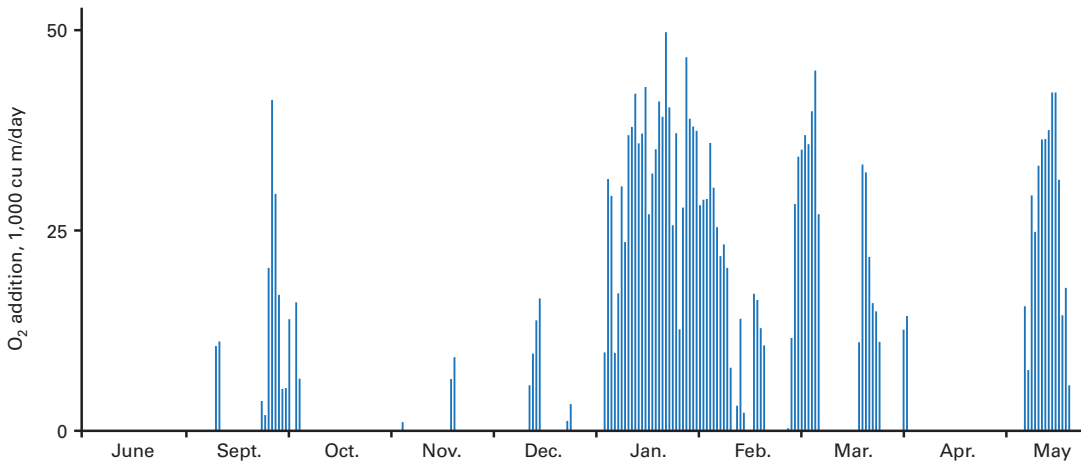
- The FCC is important for increased production of middle distillates. In particular, it can provide for better yields and reduction of residues by mixing in heavy feedstocks. But that requires more capacity and flexibility, both in the reactor and in the regenerator. Use of oxygen enrichment in regeneration can contribute substantially (Fig. 2).
- Oxygen enrichment in the FCC also helps improve efficiency by increasing capacity and flexibility in choice of feed oils to the FCC. Fig. 2 shows how oxygen enrichment in regeneration increases FCC capacity.

It also shows that the degree of conversion increases at constant feed volume with oxygen enrichment to 27 vol % in the regeneration air (solid arrows). To maximize the throughput of feedstock, one can increase the feed by about 10% (dotted arrow in Fig. 2) with a constant degree of conversion.

Conclusion: Oxygen enrichment in FCC units allows the refinery operator to increase the FCC capacity for greater throughputs, obtain higher flexibility

O_2 CONSUMPTION IN CEPSA SAN ROQUE REFINERY

Fig. 3



Source: Reference 6

in choice of feedstocks, and use heavier feedstocks.

Experience

Several major FCC units operated in oxygen enriched mode have provided operational examples.

A refiner with its own port on the Mediterranean Sea buys crude oils from the spot market and therefore treats a great variety of crudes. He uses oxygen enrichment primarily to increase flexibility in the FCCU capacity. It allows the company to operate the FCC up to 130% of the nameplate load. Correspondingly, oxygen consumption varies in a wide range (Fig. 3).

Before starting oxygen enrichment in its FCCU, a Spanish refinery conducted experiments to obtain experience with the reaction of the plant and to see whether its operators could cope with oxygen enrichment.

For the purpose, a test program was carried out varying operating parameters (Table 1). Table 2 shows the economic results of the tests.

As the results were positive, both with respect to technology and economy, the refinery decided to opt for oxygen enrichment whenever needed.

In a Chilean FCCU, the refinery tested increasing feed capacity by 15% using oxygen enrichment. As a result, the gasoline output increased by 30% and naphtha by 15%. The step reduced both fuel gas and coke.

As the operation is so economically attractive, the refinery has continued since the test without interruption for more than 4 years. As a result, the refinery is consuming about 45 tonnes/day of oxygen, which is all the O_2 the nearby air-separation unit can provide.

TEST CONDITIONS BEFORE DECISION FOR O_2 ENRICHMENT*

Table 1

	Begin tests (air)	First test (enriched air)	Second test (enriched air)	After tests (air)
Riser temperature, °C.	499	507	508	499
Feed temperature, °C.	235	235	224	233
Additional feed due to O_2 enrichment, tpd	—	**240**	**317**	—
Additional feed, % of original load	—	**4.5**	**6.0**	—

*Bolded data represent data changed for this test.

ECONOMIC RESULTS OF OXYGEN ENRICHMENT TESTS*

Table 2

	Begin tests (air)	First test (enriched air)	Second test (enriched air)	After tests (air)
Energy savings, €/day	—	**148**	**331**	—
Daily turnover, €/day	92,009	**102,346**	**102,124**	90,663
Net profit due to O_2 enrichment, €/day	—	**9,099**	**12,272**	—
€/year	—	**3,030,074**	**4,086,678**	—

*Bolded data represent data changed for this test.

Claus plants

Claus plants convert toxic hydrogen sulfide to elemental sulfur. They can also eliminate pollutants, particularly by converting ammonia to harmless materials, such as nitrogen and water.[2 3] Fig. 4 shows a Claus plant.

Existing Claus plants in refineries are usually designed to process highly concentrated hydrogen sulfide fractions with low proportions of hydrocarbons and ammonia. Older plants usually have the Claus units only without tail-gas cleanup. In practice, they have sulfur recoveries of 95-98%. But current European Union specifications require sulfur recoveries of up to 99.5%+ for units with a sulfur capacity greater than 50 tpd. Local authorities may demand even higher recovery rates, up to 99.9+%.

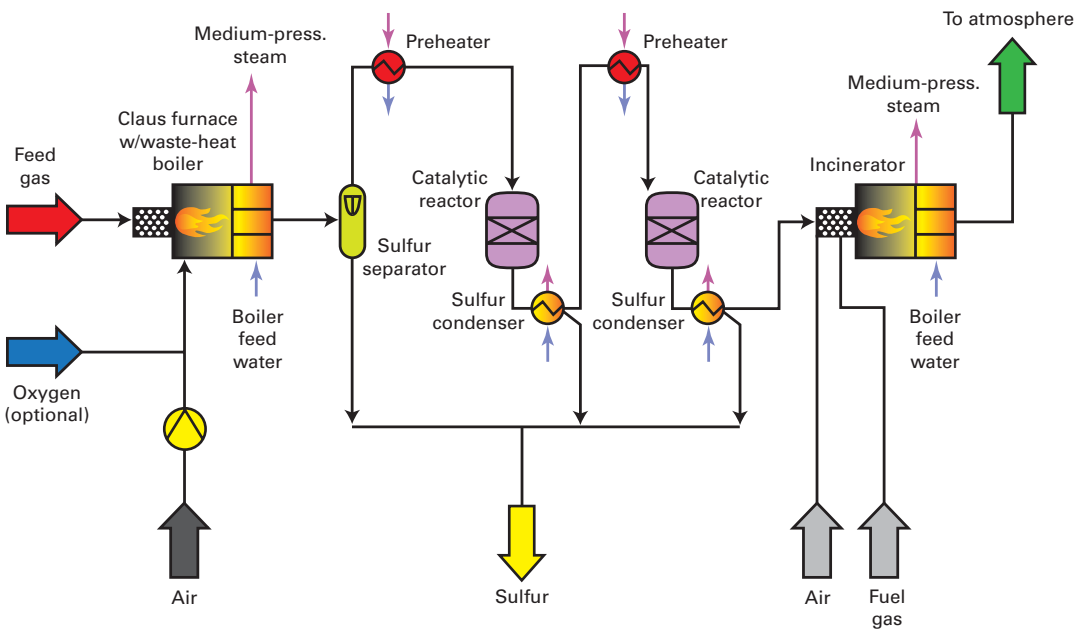
Those values can be achieved only with a tail-gas cleanup, which in turn, causes a higher pressure drop across the entire system. In general, the crude gas pressure cannot be increased much, if at all, because the gas comes from regeneration of an amine scrubber. The pressure there can be increased only by raising the regeneration temperature, which would cause more decomposition of the scrubbing agent and more

byproducts. That consequence is unacceptable.

One alternative is to enrich the combustion air in the Claus burner with oxygen. That is in itself nothing new and is described elsewhere.[1] Because of oxygen enrichment, inert nitrogen is kept out of the Claus plant due to less air flow, so that the gas volume and the pressure drop there are reduced compared with the original operation with air. The pressure difference gained by oxygen enrichment can be used to transport the gas through the subsequent tail-gas cleanup.

CLAUS PLANT

Fig. 4



Oxygen enrichment can also be used to add more crude-gas-compensating reduced air volume. This allows more sulfur to be produced in the Claus plant. Capacity increases can be as much as double.[1]

Another new and increasingly important function of Claus plants is to dispose of the additional ammonia produced in more severe hydrotreating. That is possible in Claus furnaces but requires higher temperatures, typically greater than 1,300° C., while normal operation is usually at 1,100-1,200° C.

Oxygen enrichment can solve that problem too. The flame temperature is higher when oxygen is used. Fig. 5 shows a typical temperature rise affected by oxygen enrichment: 28% O_2 results in a temperature rise of about 120° C.

The proportion of oxygen can be varied so that it ensures attaining the temperature needed to break down ammonia while still being tolerated by the furnace walls.

Conversion of existing Claus plants from use of air to oxygen enrichment is substantially less expensive than building new plants designed for the new limits. It can be assumed that conversion costs less than 10% as much as a new plant.

The oxygen is provided in the conventional manner from a tank, a pressure-swing adsorption system, or a pipeline. The optimal choice of the supply depends on the conditions at the site of the Claus plant. In most cases, however, a tank is the best choice.

One must consider that strong seasonal changes often occur in the loading of Claus plants. It is the average load of the Claus plant, not the peak load, that should be used as the basis for selection of the type of supply. That is because one needs oxygen addition only at more than 100% nameplate capacity.

As a specific example, the oxygen feed at full load was 1,000 standard cu m/hr but only 300 scm/hr at 80% load. One would probably choose a PSA supply for the peak value of 1,000 scm/hr, but in this case a tank supply would be distinctly more economical and can provide the peak value of 1,000 scm/hr with no problem.

Conclusion: Oxygen enrichment in Claus plants offers the following advantages to a refinery operator:

- Increased capacity in the Claus plant, so that the sulfur capacity can be increased by up to 100%.
- Higher flame temperature from the Claus burner, giving better conversion of pollutants, especially of ammonia.
- Lower volume of gas from the Claus plant that reduces the load on the tail-gas treatment process and fuel requirement in the incinerator.

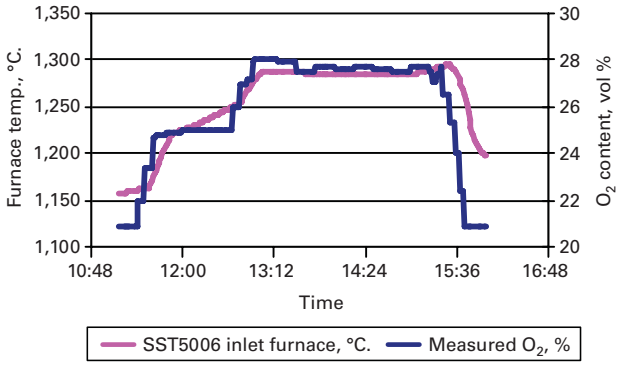
Experience

The number of Claus plants with oxygen enrichment is large already with probably more than 200 in operation. Among them are several second and third-time buyers that are content with the operation of their plants. Before installation, many of the refiners conducted tests to gain first-hand experience before choosing continuous oxygen enrichment.

The necessary hardware for testing is available for rental from the major gas companies. Especially the liquid oxygen tank, vaporizer for the liquid oxygen, and Linde's Flowtrain to meter the oxygen into the Claus plant are usually

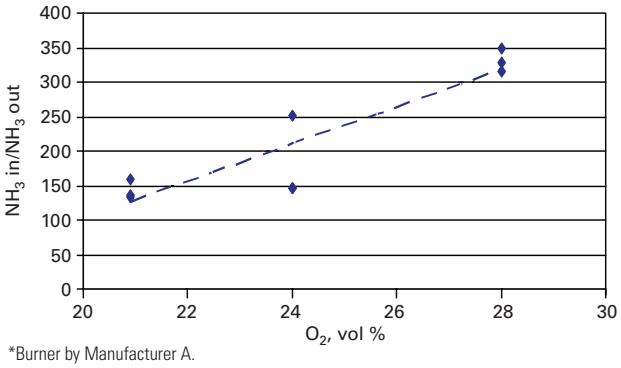
O_2 ENRICHMENT RAISES CLAUS FURNACE TEMP.

Fig. 5



AMMONIA DECOMP. EFFICIENCY W/O_2 ENRICHMENT*

Fig. 6



*Burner by Manufacturer A.

available on short notice.

The tests facilitated an overview of the Claus burner systems on the market and their abilities to convert ammonia. Measurements by Linde showed that ammonia-conversion efficiency may vary from factors of about 50/1. (ammonia in/ammonia out) to about 35,000/1. Fig. 6 shows a typical example.

Choosing the right burner and furnace configuration is important in avoiding such ammonia-related problems as corrosion and plugging by ammonium salts. Fig. 7 shows an example of an inefficient burner. Comparing it with Fig. 6 makes clear that the burner by Manufacturer A is more efficient in converting ammonia than Burner B.[3]

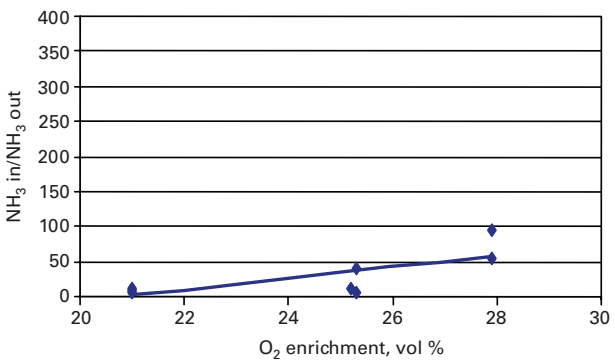
Why efficiencies of different burners may differ so much can be understood from the temperature profile in a furnace in which a conventional burner with two concentric lances was measured in comparison with a high-turbulence burner. Fig. 8 shows the results.

The measurements prove that for the conventional two-lance burner, the temperature distribution is uneven, while for the high-turbulence burner the temperature profile is flat. Correspondingly, gas distribution in the reaction chamber is uneven for the conventional burner so that not all the ammonia molecules meet the necessary oxygen molecules.

Therefore conversion remains unsatisfactory. For the high-turbulence burner, however, better conversion conditions prevail, allowing only small traces of ammonia to slip through.

AMMONIA CONVERSION IN BURNER BY MANUFACTURER B

Fig. 7



Partial oxidation

The principal function of partial oxidation is to convert liquid or solid hydrocarbons to hydrogen, carbon monoxide, carbon dioxide, and water by gasification.[5] Then the product gas can be used as synthesis gas, as fuel gas, or as crude gas for hydrogen recovery. Fig. 9 shows a partial-oxidation unit.

In the process, solid or liquid hydrocarbons are burned in the gasifier with less than stoichiometric amounts of oxygen. This produces high temperatures at which the large molecules are broken up so that the product gas contains hydrogen, carbon monoxide, carbon dioxide, and water.

The gas is cooled and contaminants are removed in various cleanup processes. The flow diagram shows a gas scrubber for removing hydrogen sulfide. The purified gas is available for further use. In particular, the carbon monoxide can be converted almost completely with water to hydrogen and carbon dioxide in a carbon monoxide shift ($CO + H_2O \rightarrow CO_2 + H_2$) which can compensate for a deficit of hydrogen in the refinery.

With respect to new developments, partial oxidation opens up several possibilities for refinery operators:

- Heavy heating oils and residues in particular can be used as feedstock to partial-oxidation plants in refineries. They can be operated practically with no limit to the pollutant content so that the feedstocks can be used economically.

Previously, the principal users of the heavy heating oils and residues were power plants and ships. That market is vanishing because those former users must also convert to low-sulfur fuels. Costs of burning high-sulfur fuels in power plants are steadily increasing because requirements for purity of waste gases are increasing and, with them,

the cost of purification. In spite of the increasingly higher costs of low-sulfur fuels, power plant operators often find that the reduced cost of waste-gas cleanup makes them more economical than cheaper but higher-sulfur fuel.

Emission of sulfur dioxide by ships, although unlimited on the high seas, is now being limited in coastal areas so that ships can no longer use high-sulfur diesel fuels. Both developments mean that the refinery operator either cannot sell high-sulfur heating oils or residues at all or it can sell them only at a low price. Using them in partial oxidation can, accordingly, both improve the refinery hydrogen balance and economically get rid of high-sulfur oils and residues.

- Gas from partial oxidation can be used for fuel in an integrated gasification combined cycle power plant.[5] This kind of power plant has particularly high efficiency and its emissions are low in pollutants. Typically, a refinery with a crude oil capacity of 10 million tpy can supply an IGCC power plant with a power of about 350 Mw.

That gives the refinery another leg to stand on. It broadens the economic base, and the refinery can react more flexibly to market requirements.

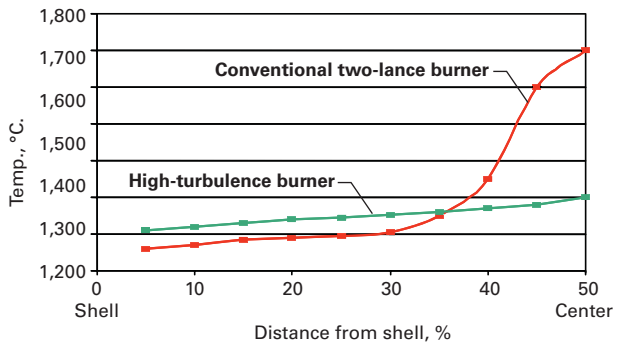
- Gasification gas from partial oxidation can also be used as a synthesis gas. For instance, it can be used, after appropriate pretreatment, for synthesis of gas to liquid, that is, production of synthetic diesel or gasoline, for methanol, or for ammonia production. This use of partial oxidation to produce chemicals also broadens the economic base of the refinery.
- Partial oxidation can handle differing feedstock compositions, within wide limits. That makes it possible to use crude oils of different qualities in the refinery and to feed residues that cannot be utilized economically in the usual refining procedure.

Not every refinery has its partial-oxidation unit, in spite of these advantages, because of the high capital investment for such a unit and that it must result in greater economic utility before it can pay off with the existing structure of a refinery. Especially for GTL, the fast rising crude oil price made production of these synthetic fuels increasingly more attractive. Of course production of this additional ultraclean fuel fits perfectly into the palette of products of a refinery.

Use of oxygen in partial oxidation thus can bring the refinery operator several advantages:

- Cleaner and more advantageous reuse of residues.
- Broadening of the economic base of the refinery.
- Wider range of products and thus greater economic flexibility of the refinery.
- A wider range of crude oil compositions to be processed.

TEMP. DISTRIBUTION IN CLAUS FURNACE* Fig. 8

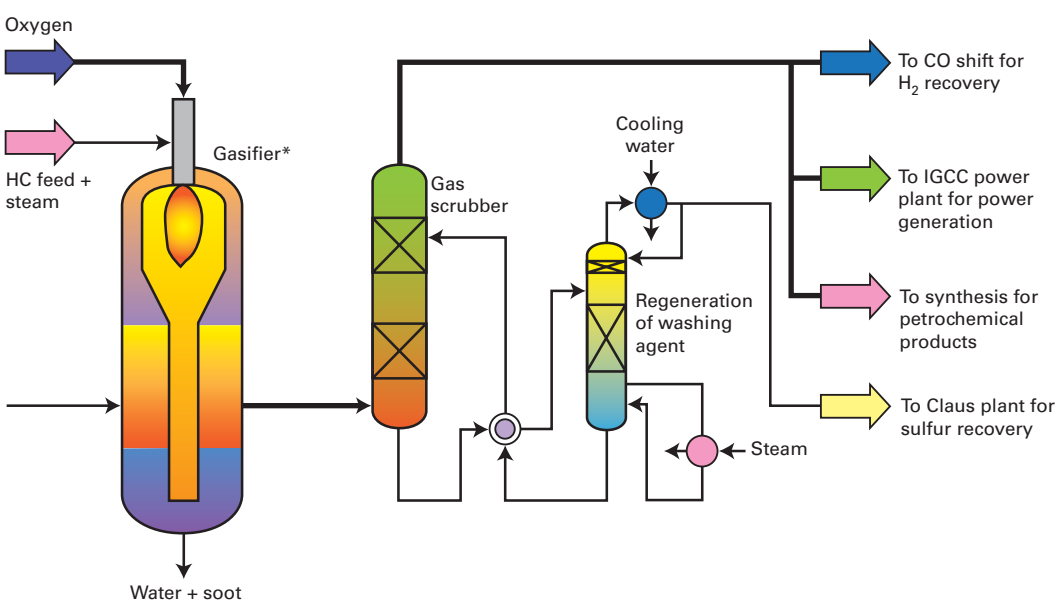


*Measurements in a plane 1 m from burner tip.

Waste water treatment

Oxygen deficiency causes many problems in waste water treatment. Refineries, in particular, with their usually highly loaded waste waters, find

GASIFICATION OF RESIDUES Fig. 9



*Texaco or Shell process, for example.

treatment capabilities rapidly becoming insufficient, and degradation processes often become anaerobic, with substantial odor emissions. These problems cause conflicts with local authorities and population.

Industrial oxygen can help to solve these problems. Solutions have already been attained for:

- Meeting peak loads in activated sludge plants with pure oxygen.
- Nitrogen elimination with pure oxygen by intermittent, simultaneous, or upstream denitrification.
- Pure oxygen for emergency use or for conversions of waste water treatment plants.
- Pure oxygen for waste water prepurification.
- Pure oxygen for conveying waste water in pressure pipes.

The oxygen required is usually injected via Venturi nozzles. The particular advantages of such system are its low capital investment and the flexible matching of oxygen supply to momentary need.

One example is process conversion of the waste water treatment plant of a refinery to nitrogen elimination using industrial oxygen. In a specific case, the treatment plant has three activated sludge basins with a total volume of 4,280 cu m. The waste water throughput is 240 cu m/hr. A 30% reserve was required in the design.

The biological oxygen demand (after keeping the sample in complete darkness at ambient temp for 5 days; BOD_5) before treatment was 150 g/cu m, with a chemical oxygen demand of 800 g/cu m and total nitrogen of 146 g/cu m. Effluent values must be guaranteed at $BOD_5 < 3$ g/cu m, COD < 30 g/cu m, and $N_{total} < 5$ g/cu m.

The intermittent denitrification process was employed in the conversion. In that process, the denitrification is done in the same basins as nitrification, but the oxygen input is cut off in the denitrification phase. Eight such injection systems can introduce 400 kg/hr of oxygen. Injecting pure oxygen makes up to 24 cycles/day possible. This ensured the required effluent values. ✦

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Nelson-Farrar cost indexes

Refinery construction (1946 basis)
(Explained in OGJ, Dec. 30, 1985, p. 145)

	1962	1980	2006	2007	2008	Aug. 2008	July 2009	Aug. 2009
Pumps, compressors, etc.	222.5	777.3	1,758.2	1,844.4	1,949.8	1,966.5	2,009.0	2,009.0
Electrical machinery	189.5	394.7	520.2	517.3	515.6	517.3	515.0	515.9
Internal-comb. engines	183.4	512.6	959.7	974.6	990.9	992.2	1,029.4	1,030.0
Instruments	214.8	587.3	1,166.0	1,267.9	1,342.1	1,356.6	1,384.6	1,390.5
Heat exchangers	183.6	618.7	1,162.7	1,342.2	1,354.6	1,374.7	1,253.8	1,253.8
Misc. equip. average	198.8	578.1	1,113.3	1,189.3	1,230.6	1,241.5	1,238.4	1,239.9
Materials component	205.9	629.2	1,273.5	1,364.8	1,572.0	1,779.8	1,296.2	1,345.0
Labor component	258.8	951.9	2,497.8	2,601.4	2,704.3	2,695.7	2,815.1	2,822.1
Refinery (Inflation) Index	237.6	822.8	2,008.1	2,106.7	2,251.4	2,329.3	2,207.5	2,231.2

Refinery operating (1956 basis)
(Explained in OGJ, Dec. 30, 1985, p. 145)

	1962	1980	2006	2007	2008	Aug. 2008	July 2009	Aug. 2009
Fuel cost	100.9	810.5	1,569.0	1,530.7	1,951.3	2,228.4	950.9	954.7
Labor cost	93.9	200.5	204.2	215.8	237.9	237.4	263.1	258.2
Wages	123.9	439.9	1,015.4	1,042.8	1,092.2	1,094.3	1,181.5	1,158.1
Productivity	131.8	226.3	497.5	483.4	460.8	460.9	449.0	448.5
Invest., maint., etc.	121.7	324.8	743.7	777.4	830.8	859.5	808.6	817.3
Chemical costs	96.7	229.2	365.4	385.9	472.5	544.0	406.7	403.9
Operating indexes								
Refinery	103.7	312.7	579.0	596.5	674.1	717.9	578.0	580.0
*Process units**	103.6	457.5	870.7	872.6	1,045.1	1,152.0	694.8	697.6

**Add separate index(es) for chemicals, if any are used. See current Quarterly Costimating, first issue, months of January, April, July, and October.*

These indexes are published in the first issue of each month. They are compiled by Gary Farrar, OGJ Contributing Editor.

Indexes of selected individual items of equipment and materials are also published on the Costimating page in the first issue of the months of January, April, July, and October.

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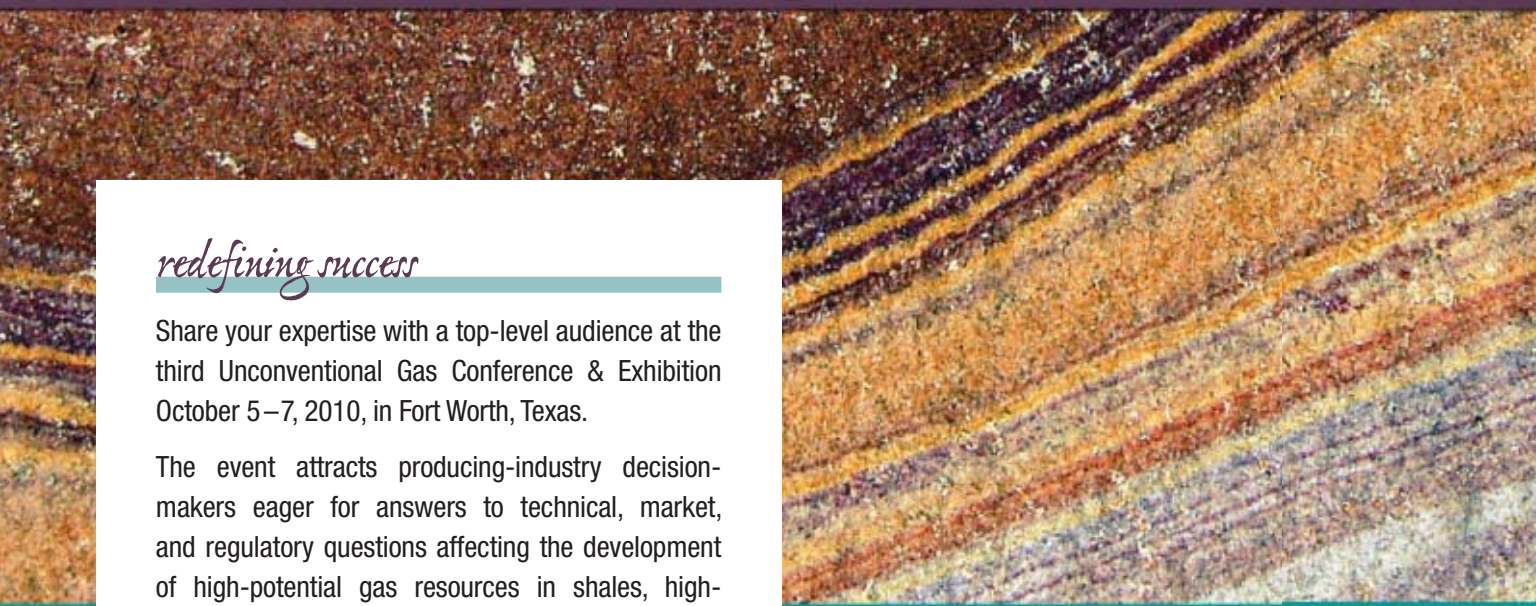

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Black Sea region stands at energy crossroads

Vlad Popovici
Toronto

The Black Sea energy landscape is going to change dramatically over the next 5-10 years, as the region's nations pursue aspirations not only to become transport hubs for oil and natural gas supplies moving into Europe but also to boost their own hydrocarbon output.

Divergent or even conflicting paths, however, still need to come together if the region is to reach its full potential, Black Sea events having ripple effects on Southeast Europe, Russia, the Caspian Sea, Middle East, and ultimately the European consuming markets.

The Nabucco and South Stream pipeline projects are just the visible part of the energy game emerging in the region. Statements in the context of the first Black Sea Energy and Economic Forum (OGJ, Sept. 21, 2009, p. 50, and Oct. 12, 2009, p. 27) and other recent events in the region allow greater understanding of the often divergent interests and strategies of the countries bordering the Black Sea. This article examines each country in turn.

Ukraine

Ukraine remains the main transit country for Russian oil and gas exports to Europe through the pipeline infrastructure developed by the former Soviet Union. About 22% of total Russian oil exports cross or are consumed in Ukraine. The natural gas percentage is even higher at more than 80% (Fig. 2). Although Ukraine has stepped up exploration efforts, its oil and gas production have remained flat for the last decade, covering slightly more than 20% of domestic oil consumption and almost 30% of gas consumption.[1]

Ukraine's strategic goals include retaining its position as the main energy transit hub for exports to Europe, decreasing its dependence on Russian oil and gas by increasing domestic production, and diversifying its import sources by directly importing Caspian oil and gas.

The country, however, faces a number of obstacles in reaching these objectives. Economic and financial woes coupled with domestic political strife and deteriorating relationships with Russia endanger Ukraine's status as the main Russian export transit country. The Soviet-era oil and gas pipeline infrastructure is old and deteriorating rapidly, and Ukraine cannot afford to maintain and upgrade it. National oil and gas company Naftogaz is technically bankrupt and cannot support development of domestic oil and gas.

Pipeline projects initiated by Ukraine to diversify oil and gas imports, such as the White Stream (Georgia-Ukraine-EU) gas pipeline and the extension of the Odessa- Brody oil pipeline to the Baltic Sea port of Gdansk (Poland), have stopped moving forward.

Ukrtransnafta, operator of the Ukrainian oil pipeline system, stopped Russian oil shipments in the Odessa-Brody pipeline in October 2009 for several weeks—forcing Lukoil's Black Sea Odessa refinery to halt activity—and reversed its flow to import oil directly

BLACK SEA REGION

Fig. 1

from Azerbaijan instead. SOCAR, the Azeri national oil and gas company, opened an office in Kyiv on Oct. 12 and has confirmed negotiations to buy another Black Sea refinery in Ukraine, the Kherson refinery.

These actions worsened Russian-Ukrainian relationships, already strained by nearly continuous natural gas import volume and transit fee disagreements. Russia and Ukraine signed a new gas supply contract after the winter 2008-09 supply crisis, but in October 2009 Ukraine announced a desire to reopen negotiations in an effort to reduce contracted volumes to 33 billion cu m/year in 2010 from 42 billion cu m/year in 2009.

Ukraine also seeks to renegotiate gas transit fees, considering Naftogaz's current annual transit revenue of roughly $2.5 billion to be less than adequate. Gazprom is strongly opposed to reopening the contract and the Ukrainian government has warned that, although it will not disrupt gas transit to Europe during winter 2009-10, it cannot guarantee transit for 2010-11 without a new contract.[2]

In its bid to increase domestic oil and gas production, Ukraine has also antagonized Romania regarding the exclusive economic zone boundary between the two countries in the northwest corner of the Black Sea (Fig. 3).

Ukraine faces an uphill battle the next 5-10 years to maintain its preferred transit country status, as internal political fights continue, competition intensifies from southern corridor projects bypassing the country, and Russia continues to block direct access of Caspian producers to Europe through Ukraine.

Existing oil, gas transmission pipelines

Fig. 2

*All or most of the oil and gas moving through a given pipeline is from Russia.
Source: US Energy Information Administration

Romania

Romania is a traditional oil and gas producer and was for a long time an oil exporter. Domestic production, however, is declining rapidly. The country produced 99,000 b/d of oil and 11.5 billion cu m of natural gas in 2008, covering 80% of domestic gas consumption, but only 44% of oil consumption.

As a member of the European Union since 2007 with more than 500,000 b/d of oil refining capacity and a well-developed oil and gas pipeline infrastructure, Romania presents an interesting potential access point to European markets for non-EU suppliers, especially Caspian producers.

Romania spent the past 20 years without a clear long-term energy strategy, other than opposing any large Russian-led project. The Romanian Energy Strategy Plan for 2007-20 does not mention any regional or European strategic objective for the energy sector.

Signs of a more structured energy strategy, however, have recently emerged. The main tenets of this strategy seem to be close cooperation with Caspian producers to allow them to access to EU markets while Romania diversifies from Russian supplies, coupled with an increased push to revive domestic oil and gas production and diversify the primary energy mix.

KazMunaiGaz, the Kazakh national oil and gas company, acquired Rompetrol in 2007. Rompetrol has distribution networks in 13 countries. Romania also signed a strategic partnership agreement with Azerbaijan and negotia-

CLAIMED MARITIME BOUNDARIES; ROMANIA, UKRAINE

Fig. 3

Source: International Court of Justice

tions between Romanian authorities and SOCAR have intensified, SOCAR promising during October 2009 talks to supply Romania with 7.3 billion cu m/year of gas if Nabucco is the first-built among the competing regional pipeline projects.

SOCAR is also interested in investing in refining capacity in Romania and, although the Romanian government has privatized all refineries, it has also announced a large state subsidy for RAFO Onesti, a money-losing privately owned refinery, intensifying speculation regarding cooperation with SOCAR regarding the facility.

Romania has unconditionally supported Nabucco since its inception and was not invited to be part of South Stream. It was also one of the initiators of the Pan-European Oil Pipeline (or Constanta-Trieste pipeline), shelved in September 2009 as Croatia reconsidered its energy project priorities and focused on projects along the Adriatic coast. Romania has also started negotiations to participate in the still-nascent White Stream project, strongly backed by Azerbaijan.

Romanian business leaders discussed the possibility of shipping LNG across the Black Sea during the Black Sea Energy and Economic Forum, an option also mentioned in late October by Azeri officials. But this option seems to be a long shot without switching to cheaper, quicker CNG instead (Fig. 4). In the meantime, the Romanian government earmarked €2 billion over the next 10 years for upgrading the country's gas transmission network, connecting it to neighboring countries, and increasing underground storage capacity.

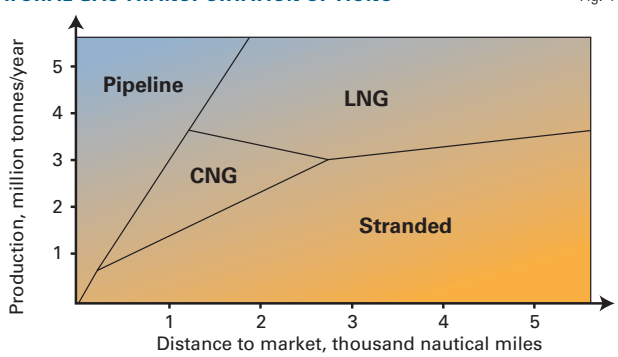
Romania on Sept. 3, 2009, launched its tenth oil and gas production licensing round, with permits to be awarded early-2010. The round offered 30 oil and gas exploration blocks, 11 of them offshore in the Black Sea.

A February 2009 decision by the International Court of Justice in the Hague settling competing claims by Romania and Ukraine regarding a 12,000 sq km offshore area thought to contain as much as 100 billion cu m of gas and 73 million bbl of oil reserves allowed opening of previously unavailable offshore blocks.[3] The ICJ awarded 9,000 sq km to Romania and the balance to Ukraine[4] and both countries accepted the decision.

Romania could become a bridge to Europe for Caspian production if it can separate internal politics from the management of its energy sector, improve the transparency of the exploration licensing process, and implement energy infrastructure projects geared toward helping it become a viable oil and gas transit country.

NATURAL GAS TRANSPORTATION OPTIONS

Fig. 4



Source: 5th Doha Conference on Natural Gas 2005

Bulgaria

Bulgaria, the other EU member in the Black Sea region, imports more than 85% of its gas and 95% of its oil from Russia. Bulgaria and Slovakia were the worst hit states during the January 2009 gas crisis in Europe. Domestic oil and gas production remains marginal (Figs. 5 and 6).

The 2002 Energy Strategy of Bulgaria document says the country should become the energy center for the Balkans. Domestic politics, however, have prevented updating this strategy to

account for new energy trends and the country's 2007 integration into the EU.

Previous governments strongly supported Russian-backed projects such as the South Stream gas pipeline and Burgas-Alexandroupolis oil pipeline, while also participating in competing projects such as Nabucco or the AMBO (Burgas-Vlora) oil pipeline. The government installed in July 2009 started to back away from these projects, only to restate interest in October 2009.

FUTURE BLACK SEA REGION PIPELINE PROJECTS

Name	Route	Capacity	Length, km	Main promoters, shareholders	Strategic goal
Oil					
Trans-Anatolia	Samsun-Ceyhan, Turkey	1-1.4 million b/d	550	Italy, Russia, Turkey	Bypass Turkish Straits
Trans-Thrace	Sayak-Ambarli-Saros, Turkey	1.4 million b/d	280	Turkey	Bypass Turkish Straits
Trans-Balkan	Burgas, Bulgaria-Alexandroupolis, Greece	0.7 million b/d	279	Bulgaria, Greece, Russia	Bypass Turkish Straits
AMBO	Burgas, Bulgaria-Vlore, Albania	0.75 million b/d	912	Albania, Bulgaria, Macedonia	Bypass Turkish Straits
Pan-European Oil Pipeline	Constanta, Romania-Trieste, Italy	1.2-1.8 million b/d	1,856	Croatia, Romania, Serbia	Bypass Turkish Straits; project suspended by Croatia September 2009
Odessa-Brody extension	Brody, Uktraine-Plock-Gdansk, Poland	0.8 million b/d	800	Azerbaijan, Georgia, Lithuania, Poland, Ukraine	Bring Caspian oil to European markets
Gas					
Nabucco	Caspian region, Middle East–Baumgarten, Austria	31 billion cu m/year	3,300	Austria, Bulgaria, Germany, Hungary, Romania, Turkey	Reduce European dependence on Russian imports
South Stream	Beregovaya, Russia-Italy	63 billion cu m/year	[1]~3,100	Bulgaria, Hungary, Italy, Russia, Serbia, Turkey	Avoid Ukraine as transit route for Russian gas exports to Europe
Blue Stream 2	Beregovaya, Russia-Samsun-Ceyhan, Turkey	—	950	Russia, Turkey	Increase Russian gas exports to Turkey, other markets
White Stream	Tbilisi-Supsa, Georgia-Constanta, Romania[2]	32 billion cu m/year	1,240	Georgia, Romania, Ukraine	Reduce European dependence on Russian imports
Bulgaria-Greece Interconnector	Stara Zagora, Bulgaria-Komotini (Greece)	1 billion cu m/year	160	Bulgaria, Greece	Reduce Bulgarian dependence on Russian gas imports

[1]900 km offshore; routes of the onshore branches to be confirmed. [2]White Stream was initially planned to go to Ukraine, but promoters indicated Fall 2009 that direct access to EU via Romania is preferable for the potential suppliers from the Caspian region.

A new draft of the national energy strategy document met with resistance from interests concerned it will create energy production overcapacity and encourage corruption in state-owned energy companies. A report published in September 2009 by the Center for the Study of Democracy says the energy sector "remains one of the least transparent and of highest corruption-risk sectors in Bulgaria."[5]

The report recommends, among other things, revising the new national energy strategy draft, energy supply diversification in the nuclear sector, and improvements in gas storage facilities and the gas transmission network, as well as more transparency and openness in general.

Bulgaria is well-positioned to become an energy hub for the Balkans, and the region has a promising potential for oil and gas infrastructure projects,[6 7] but the country has to define both its Balkan cooperation projects and how it will reconcile this Balkan-focused strategy with participation in wider-reaching energy projects.

Turkey

Turkey's growing economy depends on imports for almost 95% of oil consumption and almost 90% of gas consumption.[8] Turkey's pipeline and LNG terminal infrastructure, however, allow it the most diversified range of oil and gas imports in the Black Sea region, accessing supplies from the Middle East, Caspian Sea, Russia, and Africa.

Turkey's energy strategy centers on four main axes:

- Becoming the main energy transit hub between oil and gas producing regions and European markets.
- Diversifying oil and gas import sources.
- Diversifying its energy mix.
- Dramatically increasing domestic oil and gas production.

Turkey lies in the transit routes from Caspian, Russian, and Middle East producers to the European markets. Besides its existing oil and gas pipelines and LNG terminals, Turkey has been involved since the beginning in the Nabucco project and in 2009 joined the South Stream project. Turkey officially approved laying South Stream in its territorial waters and began preliminary route survey work Oct. 20, 2009. Turkey and Russia have also discussed a potential Blue Stream 2 gas pipeline in the Black Sea to Samsun.

Turkey also has two oil pipeline projects—Trans-Anatolia (or Samsun-Ceyhan) and Trans-Thrace—competing against the AMBO and Burgas-Alexandroupolis pipelines to bypass the Bosporus. The Trans-Thrace pipeline, promoted by local Tun Oil, is dormant, while the Trans-Anatolia pipeline, promoted initially by Italy's Eni and Turkey's Calik Holding, received a boost Oct. 19, 2009, when Russia joined Italy and Turkey in signing a joint agreement for building the pipeline. Russian companies Transneft and Rosneft have cosigned with Eni and Calik Holding a memorandum of understanding for construction of the pipeline (see table). On Oct. 27 Russia and Turkey also signed an agreement to build a refinery on the Samsun-Ceyhan pipeline.

Turkey's state Turkish Petroleum Corp. is a shareholder in the Azeri-Chirag-Guneshli and Shah Deniz fields in Azerbaijan and has exploration and

production interests in other countries in the region, such as Turkmenistan, Syria, Iraq, Egypt, and Georgia. Turkey is also using its historical and cultural ties to the Middle East region to try to secure gas supplies for the planned pipelines, holding 2009 discussions with Iraq, Iran, and Qatar to secure gas for Nabucco.

Turkey has also improved its relations with Armenia, which is starting to be viewed by some as an alternative to Georgia as a transit route from the Caspian Sea. The move angered Azerbaijan, which has a long-term conflict with Armenia, prompting Azeri threats in October 2009 to avoid Turkey as a transit country for gas from the Shah Deniz 2 project and instead study an LNG or CNG route to the western coast of the Black Sea.[9]

Turkey is actively diversifying its energy mix, having ratified the Kyoto protocol and adopted laws encouraging investment in renewable energy production. Renewable sources, mostly hydro, already meet 20% of Turkey's primary energy needs and Turkey has three nuclear plants planned.

TPAO is leading Turkish efforts to increase domestic production of oil and gas, particularly from the Black Sea. In 2006 TPAO initiated a $350 million joint venture with Petrobras covering two offshore Black Sea blocks and has also actively explored the area on its own.

Its other major Black Sea exploration partner since 2008 is ExxonMobil.[10] TPAO's CEO stated as recently as October 2009 that 10 promising areas in the Black Sea could contain recoverable reserves of up to 10 billion bbl oil and 1.5-2 trillion cu m gas, enough to allow Turkey to cover its domestic consumption and become an oil and gas exporter.[11]

TPAO started gas production in the Black Sea in 2007 but still has a lot of work to do to prove reserves of the most promising prospects and finance exploration and development, needing at least $100 billion and advanced deepwater technology. TPAO does not expect production from these fields before 2020. ✦

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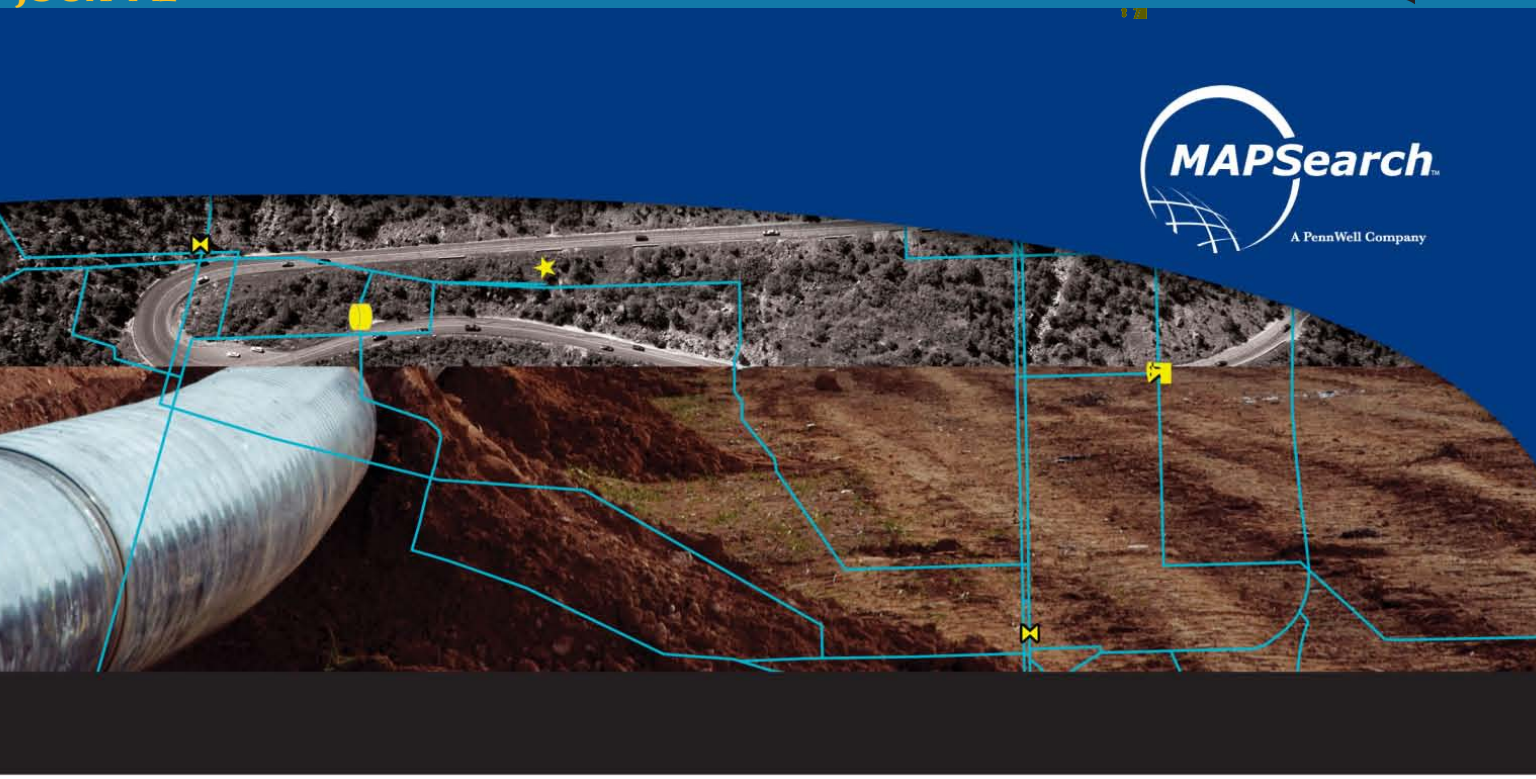
The author

Vlad Popovici is marketing manager at a major Canadian energy services company with global business coverage. He manages multiple economic and strategic assessments of pipeline projects worldwide. Popovici holds an MBA (2005) from McGill University in Montreal and has been publishing technical articles and economic analyses since 1996.



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Statistics

Imports of crude and products

	Districts 1-4		District 5		Total US		
	11-13 2009	11-6 2009	11-13 2009	11-6 2009	11-13 2009	11-6 2009	*11-14 2008
	1,000 b/d						
Total motor gasoline	584	669	0	63	584	732	860
Mo. gas. blending comp.	426	485	0	60	426	545	623
Distillate	152	177	0	0	152	177	122
Residual	267	215	0	33	267	248	241
Jet fuel-kerosine	32	23	50	12	82	35	88
Propane-propylene	152	125	10	12	162	137	146
Other	659	642	116	(2)	775	640	581
Total products	**2,272**	**2,336**	**176**	**178**	**2,448**	**2,514**	**2,661**
Total crude	**7,342**	**7,865**	**1,237**	**791**	**8,579**	**8,656**	**9,871**
Total imports	**9,614**	**10,201**	**1,413**	**969**	**11,027**	**11,170**	**12,532**

*Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Purvin & Gertz LNG netbacks—Nov. 20, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.71	4.57	5.86	4.46	5.17	5.78
Everett	3.77	2.02	3.40	2.10	2.28	4.06
Isle of Grain	3.78	2.12	3.16	2.07	2.34	3.18
Lake Charles	1.90	0.34	1.73	0.51	0.71	2.49
Sodegaura	5.25	7.55	5.50	7.23	6.49	4.34
Zeebrugge	6.16	3.96	5.48	3.85	4.55	5.54

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	13,565	55,191	38,377	12,036	74,656	13,635	4,886
PADD 2	81,837	49,272	24,239	7,925	29,326	1,187	26,405
PADD 3	168,224	68,934	39,810	13,667	47,815	17,725	31,683
PADD 4	16,033	6,083	2,056	492	3,026	228	[1]2,303
PADD 5	57,130	29,602	25,429	9,699	12,574	3,689	—
Nov. 13, 2009	**336,789**	**209,082**	**129,911**	**43,819**	**167,397**	**36,464**	**65,277**
Nov. 6, 2009	**337,676**	**210,837**	**132,030**	**44,652**	**167,725**	**36,023**	**68,424**
Nov. 14, 2008[2]	**313,548**	**198,634**	**103,764**	**38,127**	**126,880**	**39,085**	**60,415**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Refinery report—Nov. 13, 2009

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane–propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,221	1,225	2,298	45	401	107	54
PADD 2	2,925	2,911	2,295	182	915	39	236
PADD 3	6,921	6,801	2,663	593	2,041	327	677
PADD 4	541	542	305	30	171	8	[1]53
PADD 5	2,430	2,315	1,495	408	503	116	—
Nov. 13, 2009	**14,038**	**13,794**	**9,056**	**1,258**	**4,031**	**597**	**1,020**
Nov. 6, 2009	**14,125**	**13,825**	**8,919**	**1,321**	**4,054**	**681**	**1,129**
Nov. 14, 2008[2]	**14,953**	**14,558**	**8,816**	**1,385**	**4,410**	**582**	**1,037**
	17,672 Operable capacity		**79.4% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

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OIL&GAS JOURNAL online research center

OGJ crack spread

	*11-20-09	*11-21-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	83.84	58.40	25.44	43.6
Brent crude	77.14	48.45	28.69	59.2
Crack spread	6.70	9.95	-3.25	-32.7
FUTURES MARKET PRICES				
One month				
Product value	84.14	56.85	27.29	48.0
Light sweet crude	78.36	52.50	25.86	49.3
Crack spread	5.78	4.35	1.43	33.0
Six month				
Product value	91.29	64.80	26.49	40.9
Light sweet crude	81.83	56.68	25.15	44.4
Crack spread	9.46	8.12	1.35	16.6

*Average for week ending.
Source: Oil & Gas Journal
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 11-18-09	Pump price* 11-18-09	Pump price 11-19-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	226.3	257.7	216.7
Baltimore	218.4	260.3	213.2
Boston	218.8	260.7	213.3
Buffalo	208.8	272.0	203.2
Miami	224.1	277.0	216.1
Newark	219.4	252.3	208.1
New York	208.4	271.6	216.5
Norfolk	212.7	250.4	203.2
Philadelphia	217.3	268.0	215.8
Pittsburgh	216.0	266.7	219.7
Wash., DC	228.1	270.0	223.4
PAD I avg	218.0	264.3	213.6
Chicago	234.4	289.5	219.0
Cleveland	230.2	276.6	204.0
Des Moines	212.3	252.7	192.4
Detroit	228.1	279.7	214.0
Indianapolis	224.4	274.5	209.0
Kansas City	204.0	239.7	182.3
Louisville	222.7	263.6	207.0
Memphis	204.8	244.6	193.0
Milwaukee	218.3	269.6	207.3
Minn.-St. Paul	218.1	263.7	203.4
Oklahoma City	191.3	226.7	179.6
Omaha	203.7	249.4	183.4
St. Louis	203.1	238.8	193.8
Tulsa	188.2	223.6	180.4
Wichita	198.2	241.6	188.6
PAD II avg	212.1	255.6	197.2
Albuquerque	213.2	250.4	202.5
Birmingham	216.1	255.4	193.6
Dallas-Fort Worth	209.0	247.4	188.1
Houston	211.1	249.5	181.9
Little Rock	204.2	244.4	196.4
New Orleans	217.5	255.9	204.1
San Antonio	213.9	252.3	203.0
PAD III avg	212.2	250.8	195.7
Cheyenne	221.4	253.8	193.0
Denver	219.0	259.4	216.6
Salt Lake City	211.1	254.0	197.3
PAD IV avg	217.2	255.7	202.3
Los Angeles	232.1	297.9	240.9
Phoenix	220.5	257.9	230.8
Portland	237.5	280.9	245.7
San Diego	233.1	298.9	250.8
San Francisco	239.1	304.9	249.1
Seattle	239.0	294.9	240.8
PAD V avg	233.6	289.2	243.0
Week's avg.	**217.1**	**261.9**	**208.1**
Oct. avg.	**208.4**	**253.6**	**317.6**
Sept. avg.	**211.0**	**256.6**	**367.2**
2009 to date	**184.0**	**229.5**	--
2008 to date	**297.9**	**342.1**	--

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

REFINED PRODUCT PRICES

	11-13-09 ¢/gal		11-13-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	192.44	New York Harbor	193.25
Gulf Coast	186.81	Gulf Coast	190.25
Los Angeles	188.06	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	191.21	ARA	191.29
Singapore	192.43	Singapore	197.38
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	189.56	New York Harbor	169.36
Gulf Coast	185.31	Gulf Coast	169.95
Los Angeles	192.56	Los Angeles	186.57
		ARA	171.92
		Singapore	175.88

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

BAKER HUGHES RIG COUNT

	11-20-09	11-21-08
Alabama	4	4
Alaska	9	10
Arkansas	39	57
California	24	42
Land	23	42
Offshore	1	0
Colorado	31	123
Florida	0	1
Illinois	1	1
Indiana	3	2
Kansas	21	10
Kentucky	11	12
Louisiana	172	192
N. Land	116	102
S. Inland waters	13	21
S. Land	12	19
Offshore	31	50
Maryland	0	0
Michigan	0	1
Mississippi	6	18
Montana	6	7
Nebraska	1	0
New Mexico	46	74
New York	3	5
North Dakota	58	90
Ohio	8	12
Oklahoma	79	190
Pennsylvania	63	27
South Dakota	0	1
Texas	441	885
Offshore	3	7
Inland waters	0	1
Dist. 1	22	27
Dist. 2	16	33
Dist. 3	31	64
Dist. 4	28	91
Dist. 5	64	167
Dist. 6	49	125
Dist. 7B	15	27
Dist. 7C	41	65
Dist. 8	79	127
Dist. 8A	23	31
Dist. 9	28	42
Dist. 10	42	78
Utah	19	44
West Virginia	21	34
Wyoming	39	82
Others—HI-1; NV-2; OR-1; TN-1; VA-3	8	17
Total US	**1,113**	**1,941**
Total Canada	**293**	**400**
Grand total	**1,406**	**2,341**
US Oil rigs	375	419
US Gas rigs	726	1,511
Total US offshore	36	62
Total US cum. avg. YTD	**1,081**	**1,888**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	11-20-09 Rig count	11-20-09 Percent footage*	11-21-08 Rig count	11-21-08 Percent footage*
0-2,500	85	2.3	85	3.5
2,501-5,000	66	69.6	136	53.6
5,001-7,500	122	27.8	253	13.4
7,501-10,000	22	7.2	447	2.6
10,001-12,500	225	13.7	419	2.1
12,501-15,000	156	1.9	384	—
15,001-17,500	150	—	166	—
17,501-20,000	63	—	74	—
20,001-over	12	—	36	—
Total	**901**	**11.7**	**2,000**	**6.5**
INLAND	18		31	
LAND	1,069		1,915	
OFFSHORE	33		54	

*Rigs employed under footage contracts.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]11-20-09	[2]11-21-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	22
Alaska	697	725
California	650	651
Colorado	65	67
Florida	5	6
Illinois	25	25
Kansas	108	110
Louisiana	1,398	1,004
Michigan	17	16
Mississippi	63	62
Montana	85	86
New Mexico	167	166
North Dakota	201	213
Oklahoma	179	181
Texas	1,385	1,317
Utah	64	65
Wyoming	147	147
All others	66	72
Total	**5,342**	**4,935**

[1]OGJ estimate. [2]Revised.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

	11-20-09 $/bbl*
Alaska-North Slope 27°	64.51
South Louisiana Sweet	76.75
California-Midway Sunset 13°	67.85
Lost Hills 30°	75.85
Wyoming Sweet	67.22
East Texas Sweet	72.75
West Texas Sour 34°	68.25
West Texas Intermediate	73.25
Oklahoma Sweet	73.25
Texas Upper Gulf Coast	66.25
Michigan Sour	65.25
Kansas Common	72.25
North Dakota Sweet	62.75

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	11-13-09
United Kingdom-Brent 38°	76.60
Russia-Urals 32°	76.13
Saudi Light 34°	75.71
Dubai Fateh 32°	78.09
Algeria Saharan 44°	77.21
Nigeria-Bonny Light 37°	78.34
Indonesia-Minas 34°	81.14
Venezuela-Tia Juana Light 31°	76.30
Mexico-Isthmus 33°	76.19
OPEC basket	77.13
Total OPEC[2]	76.57
Total non-OPEC[2]	75.66
Total world[2]	76.17
US imports[3]	74.45

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	11-13-09	11-6-09	11-13-08	Change, %
	bcf			
Producing region	1,208	1,199	974	**24.0**
Consuming region east	2,101	2,093	2,041	**2.9**
Consuming region west	524	521	473	**10.8**
Total US	**3,833**	**3,813**	**3,488**	**9.9**
	Aug. 09	**Aug. 08**	**Change, %**	
Total US[2]	**3,352**	**2,867**	**16.9**	

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available in OGJ Online Research Center.

Imports of crude and products

	Districts 1-4		District 5		Total US		
	11-20 2009	11-13 2009	11-20 2009	11-13 2009	11-20 2009	11-13 2009	*11-21 2008
	1,000 b/d						
Total motor gasoline	873	584	55	0	928	584	980
Mo. gas. blending comp.	736	426	52	0	788	426	911
Distillate	234	152	0	0	234	152	234
Residual	279	267	50	0	329	267	392
Jet fuel-kerosine	37	32	65	50	102	82	77
Propane-propylene	153	152	7	10	160	162	233
Other	213	659	16	116	229	775	221
Total products	**2,525**	**2,272**	**245**	**176**	**2,770**	**2,448**	**3,048**
Total crude	**7,928**	**7,342**	**1,022**	**1,237**	**8,950**	**8,579**	**10,959**
Total imports	**10,453**	**9,614**	**1,267**	**1,413**	**11,720**	**11,027**	**14,007**

*Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Purvin & Gertz LNG netbacks—Nov. 27 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.71	4.52	5.87	4.41	5.17	5.79
Everett	3.81	2.11	3.44	2.20	2.67	4.10
Isle of Grain	3.56	1.98	3.05	1.88	2.44	3.04
Lake Charles	2.14	0.44	1.98	0.60	0.84	2.58
Sodegaura	5.18	7.55	5.43	7.24	6.49	4.48
Zeebrugge	6.16	3.98	5.50	3.87	4.59	5.56

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	13,514	56,191	38,881	11,956	75,804	14,034	5,093
PADD 2	83,085	49,882	24,518	7,455	28,834	1,221	25,131
PADD 3	171,107	68,114	39,405	13,260	47,455	17,914	31,602
PADD 4	16,005	6,478	2,244	625	3,129	225	[1]2,223
PADD 5	54,097	29,420	25,271	9,092	11,646	3,535	—
Nov. 20, 2009	**337,808**	**210,085**	**130,319**	**42,388**	**166,868**	**36,929**	**64,049**
Nov. 13, 2009	**336,789**	**209,082**	**129,911**	**43,819**	**167,397**	**36,464**	**65,484**
Nov. 21, 2008[2]	**320,828**	**200,476**	**105,270**	**38,005**	**126,694**	**38,842**	**60,292**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Refinery report—Nov. 20, 2009

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane–propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,234	1,230	2,338	46	409	118	53
PADD 2	2,988	2,977	2,314	202	909	53	258
PADD 3	7,009	6,919	2,706	667	2,038	375	663
PADD 4	552	548	335	27	185	9	[1]58
PADD 5	2,399	2,297	1,491	374	438	100	—
Nov. 20, 2009	**14,182**	**13,971**	**9,184**	**1,316**	**3,979**	**655**	**1,032**
Nov. 13, 2009	**14,038**	**13,794**	**9,056**	**1,258**	**4,031**	**597**	**1,020**
Nov. 21, 2008[2]	**15,173**	**14,838**	**8,962**	**1,447**	**4,609**	**555**	**1,052**
	17,672 Operable capacity		**80.3% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OIL&GAS JOURNAL online research center

OGJ crack spread

	*11-27-09	*11-28-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	82.28	58.90	23.38	39.7
Brent crude	76.74	49.77	26.97	54.2
Crack spread	5.54	9.13	–3.59	–39.3
FUTURES MARKET PRICES				
One month				
Product value	82.51	57.70	24.81	43.0
Light sweet crude	76.90	53.54	23.36	43.6
Crack spread	5.61	4.17	1.44	34.7
Six month				
Product value	89.81	66.24	23.57	35.6
Light sweet crude	81.21	59.11	22.10	37.4
Crack spread	8.60	7.13	1.47	20.6

*Average for week ending.
Source: Oil & Gas Journal
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 11-25-09	Pump price* 11-25-09	Pump price 11-26-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	225.8	257.2	198.8
Baltimore	217.8	259.7	191.0
Boston	217.9	259.8	194.4
Buffalo	208.1	271.3	191.7
Miami	223.4	276.3	198.0
Newark	218.8	251.7	196.6
New York	207.9	271.1	202.8
Norfolk	212.0	249.7	191.7
Philadelphia	216.6	267.3	201.9
Pittsburgh	215.1	265.8	206.5
Wash., DC	227.4	269.3	211.1
PAD I avg	217.3	263.6	198.6
Chicago	232.0	287.1	196.9
Cleveland	227.7	274.1	180.6
Des Moines	209.8	250.2	178.1
Detroit	225.6	277.2	190.6
Indianapolis	222.0	272.1	186.9
Kansas City	201.5	237.2	170.0
Louisville	220.2	261.1	182.9
Memphis	202.3	242.1	176.3
Milwaukee	215.8	267.1	183.0
Minn.-St. Paul	215.6	261.2	181.1
Oklahoma City	188.8	224.2	169.8
Omaha	201.4	247.1	171.7
St. Louis	200.5	236.2	181.9
Tulsa	185.7	221.1	171.4
Wichita	195.7	239.1	176.1
PAD II avg	209.6	253.1	179.8
Albuquerque	212.5	249.7	190.1
Birmingham	215.1	254.4	181.8
Dallas-Fort Worth	208.3	246.7	176.0
Houston	210.4	248.8	171.2
Little Rock	203.5	243.7	185.4
New Orleans	216.5	254.9	190.6
San Antonio	213.0	251.4	190.9
PAD III avg	211.3	250.0	183.7
Cheyenne	221.8	254.2	177.6
Denver	219.0	259.4	197.5
Salt Lake City	211.0	253.9	181.7
PAD IV avg	217.3	255.8	185.6
Los Angeles	232.1	297.9	217.6
Phoenix	220.5	257.9	207.5
Portland	237.5	280.9	222.5
San Diego	233.1	298.9	227.5
San Francisco	239.1	304.9	223.6
Seattle	239.0	294.9	217.5
PAD V avg	233.6	289.2	219.4
Week's avg.	**215.9**	**260.7**	**191.5**
Nov. avg.	**218.8**	**263.6**	**215.5**
Oct. avg.	**208.4**	**253.6**	**317.6**
2008 to date	**184.7**	**230.2**	—
2007 to date	**294.8**	**339.0**	—

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

REFINED PRODUCT PRICES

	11-20-09 ¢/gal		11-20-09 ¢/gal
Spot market product prices			
Motor gasoline		Heating oil No. 2	
(Conventional-regular)	198.88	New York Harbor	195.00
New York Harbor	198.88	Gulf Coast	192.75
Gulf Coast	192.38	Gas oil	
Los Angeles	192.80	ARA	192.57
Amsterdam-Rotterdam-Antwerp (ARA)	196.17	Singapore	199.05
Singapore	194.76	Residual fuel oil	
Motor gasoline		New York Harbor	171.50
(Reformulated-regular)		Gulf Coast	173.14
New York Harbor	196.88	Los Angeles	190.34
Gulf Coast	192.30	ARA	179.74
Los Angeles	198.80	Singapore	176.99

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

BAKER HUGHES RIG COUNT

	11-27-09	11-28-08
Alabama	4	4
Alaska	8	12
Arkansas	40	57
California	24	40
Land	23	40
Offshore	1	0
Colorado	41	121
Florida	0	1
Illinois	0	1
Indiana	3	2
Kansas	18	10
Kentucky	12	3
Louisiana	169	190
N. Land	115	98
S. Inland waters	13	21
S. Land	10	22
Offshore	31	49
Maryland	0	0
Michigan	0	1
Mississippi	6	17
Montana	7	7
Nebraska	0	0
New Mexico	47	69
New York	3	4
North Dakota	59	86
Ohio	8	12
Oklahoma	86	176
Pennsylvania	64	27
South Dakota	0	1
Texas	452	890
Offshore	2	7
Inland waters	0	1
Dist. 1	21	27
Dist. 2	13	34
Dist. 3	36	68
Dist. 4	31	88
Dist. 5	64	166
Dist. 6	53	124
Dist. 7B	16	28
Dist. 7C	39	66
Dist. 8	82	127
Dist. 8A	23	29
Dist. 9	30	47
Dist. 10	42	78
Utah	18	39
West Virginia	22	11
Wyoming	38	76
Others—HI-1; NV-2; OR-1 TN-1 VA-3	8	9
Total US	**1,137**	**1,866**
Total Canada	**317**	**406**
Grand total	**1,454**	**2,272**
US Oil rigs	379	412
US Gas rigs	748	1,443
Total US offshore	35	61
Total US cum. avg. YTD	**1,081**	**1,887**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	Rig count	11-27-09 Percent footage*	Rig count	11-28-08 Percent footage*
0-2,500	80	1.2	82	3.6
2,501-5,000	63	69.8	134	54.4
5,001-7,500	124	25.0	244	13.9
7,501-10,000	226	6.6	448	2.6
10,001-12,500	241	12.8	415	1.9
12,501-15,000	159	3.1	374	—
15,001-17,500	152	—	165	—
17,501-20,000	59	—	76	—
20,001-over	30	—	34	—
Total	**1,134**	**11.1**	**1,972**	**6.5**
INLAND	17		29	
LAND	1,084		1,893	
OFFSHORE	33		50	

*Rigs employed under footage contracts.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]11-27-09	[2]11-28-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	22
Alaska	701	728
California	651	651
Colorado	65	67
Florida	5	6
Illinois	26	25
Kansas	108	110
Louisiana	1,401	1,068
Michigan	17	15
Mississippi	63	61
Montana	85	86
New Mexico	166	165
North Dakota	205	216
Oklahoma	180	183
Texas	1,390	1,337
Utah	65	65
Wyoming	150	147
All others	66	72
Total	**5,364**	**5,024**

[1]OGJ estimate. [2]Revised.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

	11-27-09 $/bbl*
Alaska-North Slope 27°	64.51
South Louisiana Sweet	76.00
California-Midway Sunset 13°	67.20
Lost Hills 30°	75.20
Wyoming Sweet	66.55
East Texas Sweet	72.00
West Texas Sour 34°	67.50
West Texas Intermediate	72.50
Oklahoma Sweet	72.50
Texas Upper Gulf Coast	65.50
Michigan Sour	64.50
Kansas Common	71.50
North Dakota Sweet	62.00

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	11-20-09
United Kingdom-Brent 38°	77.00
Russia-Urals 32°	76.50
Saudi Light 34°	76.51
Dubai Fateh 32°	78.14
Algeria Saharan 44°	77.96
Nigeria-Bonny Light 37°	79.03
Indonesia-Minas 34°	81.28
Venezuela-Tia Juana Light 31°	76.40
Mexico-Isthmus 33°	76.29
OPEC basket	77.61
Total OPEC[2]	77.11
Total non-OPEC[2]	75.72
Total world[2]	76.50
US imports[3]	74.36

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	11-20-09	11-13-09	11-20-08	Change, %
	bcf			
Producing region	1,211	1,208	966	**25.4**
Consuming region east	2,099	2,101	1,997	**5.1**
Consuming region west	525	524	468	**12.2**
Total US	**3,835**	**3,833**	**3,431**	**11.8**
	Aug. 09	**Aug. 08**	**Change %**	
Total US[2]	**3,352**	**2,867**	**16.9**	

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available in OGJ Online Research Center.

Statistics

PACE REFINING MARGINS

	Sept. 2009	Oct. 2009	Nov. 2009	Nov. 2008	– 2009 vs. 2008 – Change	Change, %
			$/bbl			
US Gulf Coast						
West Texas Sour	3.15	2.99	1.51	9.81	–8.31	–84.7
Composite US Gulf Refinery	4.35	4.51	3.11	7.57	–4.46	–58.9
Arabian Light	0.19	1.40	2.17	5.42	–3.24	–59.9
Bonny Light	0.94	1.75	–0.74	1.23	–1.97	–159.6
US PADD II						
Chicago (WTI)	3.74	3.66	0.15	8.47	–8.33	–98.3
US East Coast						
NY Harbor (Arab Med)	0.19	0.22	1.97	4.29	–2.32	–54.1
East Coast Comp-RFG	2.91	3.27	1.98	4.80	–2.81	–58.7
US West Coast						
Los Angeles (ANS)	16.08	9.94	7.55	4.72	2.83	59.8
NW Europe						
Rotterdam (Brent)	1.64	1.30	0.85	2.56	–1.71	–66.7
Mediterranean						
Italy (Urals)	–0.45	–1.69	–2.75	4.79	–7.54	–157.3
Far East						
Singapore (Dubai)	1.30	–0.41	–1.00	2.50	1.50	–60.0

Source: Jacobs Consultancy Inc.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Aug. 2009	July 2009	Aug. 2008	Aug. 2009-2008 change	Total YTD 2009	Total YTD 2008	YTD 2009-2008 change
				bcf			
DEMAND							
Consumption	1,727	1,643	1,685	42	15,291	15,856	–565
Addition to storage	356	413	442	–86	2,462	2,300	162
Exports	70	77	70	0	689	674	15
Canada	37	42	29	8	452	383	69
Mexico	31	31	35	–4	218	257	–39
LNG	2	4	6	–4	19	34	–15
Total demand	**2,153**	**2,133**	**2,197**	**–44**	**18,442**	**18,830**	**–388**
SUPPLY							
Production (dry gas)	1,787	1,778	1,769	18	14,079	13,692	387
Supplemental gas	6	5	5	1	41	34	7
Storage withdrawal	88	83	91	–3	1,931	2,312	–381
Imports	308	313	328	–20	2,497	2,663	–166
Canada	272	267	289	–17	2,156	2,407	–251
Mexico	1	2	4	–3	20	17	3
LNG	35	44	35	0	321	239	82
Total supply	**2,189**	**2,179**	**2,193**	**–4**	**18,548**	**18,701**	**–153**

NATURAL GAS IN UNDERGROUND STORAGE

	Aug. 2009	July 2009	June 2009	Aug. 2008	Change
			bcf		
Base gas	4,268	4,266	4,260	4,228	40
Working gas	3,352	3,086	2,752	2,867	485
Total gas	**7,620**	**7,352**	**7,012**	**7,095**	**525**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

WORLDWIDE NGL PRODUCTION

	Aug. 2009	July 2009	8 month average production 2009	8 month average production 2008	Change vs. previous year Volume	Change vs. previous year %
			1,000 b/d			
Brazil	76	73	78	87	–9	–10.0
Canada	586	587	570	644	–74	–11.5
Mexico	373	366	371	369	2	0.5
United States	1,896	1,884	1,854	1,844	10	0.5
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	200	188	201	195	6	3.1
Western Hemisphere	**3,331**	**3,298**	**3,274**	**3,339**	**–65**	**–1.9**
Norway	273	285	277	288	–10	–3.6
United Kingdom	71	127	131	163	–32	–19.6
Other Western Europe	10	9	10	10	—	2.1
Western Europe	**354**	**421**	**418**	**460**	**–42**	**–9.1**
Russia	436	429	417	421	–5	–1.1
Other FSU	150	150	150	150	—	—
Other Eastern Europe	14	14	15	16	–1	–5.2
Eastern Europe	**565**	**592**	**575**	**586**	**–12**	**–2.0**
Algeria	350	347	343	355	–13	–3.6
Egypt	70	70	70	70	—	—
Libya	80	80	80	80	—	—
Other Africa	131	131	131	129	2	1.4
Africa	**628**	**619**	**623**	**635**	**–12**	**–1.9**
Saudi Arabia	1,572	1,547	1,419	1,440	–21	–1.5
United Arab Emirates	250	250	250	250	—	—
Other Middle East	835	835	835	879	–44	–5.0
Middle East	**2,657**	**2,632**	**2,504**	**2,569**	**–65**	**–2.5**
Australia	77	74	69	66	3	5.1
China	650	650	650	628	23	3.6
India	—	—	—	—	—	—
Other Asia-Pacific	169	169	169	179	–10	–5.7
Asia-Pacific	**896**	**893**	**888**	**873**	**16**	**1.8**
TOTAL WORLD	**8,470**	**8,465**	**8,290**	**8,463**	**-173**	**-2.0**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

OXYGENATES

	Sept. 2009	Aug. 2009	Change	YTD 2009	YTD 2008	Change
			1,000 bbl			
Fuel ethanol						
Production	21,752	22,552	–800	185,177	159,483	25,694
Stocks	15,688	15,001	687	15,688	15,994	–306
MTBE						
Production	1,386	1,620	–234	13,469	13,281	188
Stocks	543	608	–65	543	1,058	–515

Source: DOE Petroleum Supply Monthly.
Data available in OGJ Online Research Center.

US COOLING DEGREE-DAYS

	Sept. 2009	Sept. 2008	Normal	2009 % change from normal	Total degree-days Jan. 1 through Sept. 30 2009	2008	Normal	% change from normal
New England	36	50	22	63.6	395	490	417	–5.3
Middle Atlantic	42	82	59	–28.8	594	731	651	–8.8
East North Central	54	64	60	–10.0	529	643	701	–24.5
West North Central	84	71	87	–3.4	717	792	915	–21.6
South Atlantic	288	290	259	11.2	1,876	1,879	1,756	6.8
East South Central	258	252	209	23.4	1,539	1,572	1,485	3.6
West South Central	332	291	345	–3.8	2,472	2,322	2,274	8.7
Mountain	212	180	167	26.9	1,297	1,257	1,184	9.5
Pacific	219	176	125	75.2	886	883	663	33.6
US average*	**176**	**170**	**155**	**13.5**	**1,179**	**1,209**	**1,141**	**3.3**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
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Affordable energy isn't only target of climate politics

In the rush to cut emissions of greenhouse gases, sharp increases in energy costs won't be enough to meet targets now in place.

Yet even those aggressive and largely unmet targets, set by the expiring Kyoto Treaty, won't have much effect on global average temperature, supporters and opponents of the effort agree.

More will be needed if changes in

The Editor's Perspective

by Bob Tippee, Editor

human activity are to influence climate measurably. Recent events show what might be in store.

In the UK, Lord Smith of Finsbury has proposed that citizens be assigned carbon rations and forced to pay for excessive use of products associated with the release of carbon dioxide.

According to the Telegraph newspaper, Brits would receive accounts against which carbon use would be credited for purchases of, for example, fuel, airline tickets, and electricity. Above-ration users would have to buy credits, which below-ration users could sell.

An Environment Agency official assured the paper that costs would hit only persons with "extravagant lifestyles."

Also in the UK, Lord Stern of Brentford, who wrote a controversial 2006 study on global warming, has reinvigorated suggestions that people quit eating meat.

"Meat is a wasteful use of water and creates a lot of greenhouse gases," largely from flatulence of sheep and cattle, he told Channel 4 News. "A vegetarian diet is better."

He said he hopes climate change negotiations in Copenhagen next month yield increased meat prices.

The anticarnivorous response to global warming is a pet cause of Rajendra Pachauri, chairman of the Intergovernmental Panel on Climate Change (OGJ, Sept. 22, 2008, p. 80). He's a vegetarian.

Now California, never to be outdone when there's governance to be performed, has cracked down on outsize televisions. Tubes with screens above certain dimensions will have to meet tough new limits on energy use. The California Energy Commission says televisions can account for 10% of a home's electricity use.

But commissioners haven't thought this through. What's the effect on climate if Californians, denied the chance to watch ballgames on wide screens at home, drive their SUVs to sports bars instead and eat hamburgers with their (carbonated) beer?

(Online Nov. 20, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude, distillates in floating storage

Although it's difficult to assess precisely how much crude and distillate fuel are now held in floating storage around the globe, the associated risk is increasing significantly, said Olivier Jakob at Petromatrix, Zug, Switzerland.

It "used to be that in a period of low demand, refineries would run until the onshore stocks would be filled up, then the contango would pressure the refinery margins, which would then limit refinery production until stocks start to draw. However, the total collapse in trade following the credit crisis at the end of 2008 and the zero interest rate policy of the US Federal Reserve has brought an additional and almost indefinite level of storage tanks through the use of ships as floating stocks. This means that refineries have been producing way over what should have been the balancing economics," Jakob said.

The International Energy Agency estimated 60 million bbl of oil and 80 million bbl of distillates were in floating storage at the end of October. The Organization of Petroleum Exporting Countries put the numbers at 40 million bbl of crude and 90 million bbl of distillates. ICAP Shipping International Ltd. projected 90 million bbl of distillates would be in floating storage by the end of November, growing to 97 million bbl in December—a fivefold increase in floating distillate stocks within 9 months, said Jakob.

"If the current rate of increase in distillate floating stocks continues, we would have at the end of March 2010 more distillate stocks on water then we had in March 2008 in the total onshore US," he said.

At a 40% processing yield, it took 250 million bbl of crude to produce the 100 million bbl of distillates that went into floating storage this year, said Jakob. Add 50 million bbl of crude in floating storage, "and that makes...300 million bbl of crude oil equivalent that will come back to the market in the short to medium term," Jakob said. "On an annualized basis, this amounts to about 800,000 b/d."

Coincidentally, OPEC expects world demand for crude to increase by 800,000 b/d 2010. That could be satisfied by the drawdown of floating inventories, which "would leave onshore stocks basically unchanged from the current record highs, while the supply and demand equation will still have to deal with some increase in non-OPEC and noncore OPEC crude production," Jakob predicted.

$100/bbl crude

In a move little noticed by most oil market observers, the benchmark US light, sweet crudes contract for delivery in December 2017 briefly traded at $100.24/bbl on Nov. 18 before closing at $99.66/bbl on the New York Mercantile Exchange.

"That is the first time this year that any part of the on-exchange curve has traded above $100/bbl," said Paul Horsnell, managing director and head of commodities research at Barclays Capital in London. "Indeed, it is the first time since the start of October 2008 that has happened. A small event in itself, but symbolic nonetheless. The ledger will show that oil did trade above $100 in 2009, albeit that it took until November to happen and occurred right at the back end of the exchange-traded curve."

Moreover, Horsnell said, the December 2017 contract "has been loaded with more symbolism than you could shake a Dan Brown novel at." Brown is the author of The DaVinci Code and Angels & Demons, mysteries in which the protagonists follow obscure clues involving religious symbols. Example: the crude contract for that month never fell below $70/bbl, not even on Feb. 18 when the front-month March contract dropped to $34.62/bbl on NYMEX.

"The contract has spent the past 4 weeks between $95 and $100/bbl and has averaged just over $86/bbl for the year to date," Horsnell reported Nov. 18. "In other words, the closest thing the formal oil exchanges have for a proxy for the long-term sustainable price of oil never fell below $70 even when the consensus expected a severe multiyear economic discontinuity. Further, it has averaged $86/bbl in the depths of a recession, and has returned to $100 when the economic weakness proved to be more of a short-term shock than a multiyear trauma."

Meanwhile, he said, "The front of the curve has remained severely range bound. In our view, $70/bbl is now looking like the minimum sustainable price that would not severely depress long-term investment, and moves below that level would threaten to intensify the expected supply tightness that has kept the back of the curve so well supported."

(Online Nov. 30, 2009; author's e-mail: samf@ogjonline.com)

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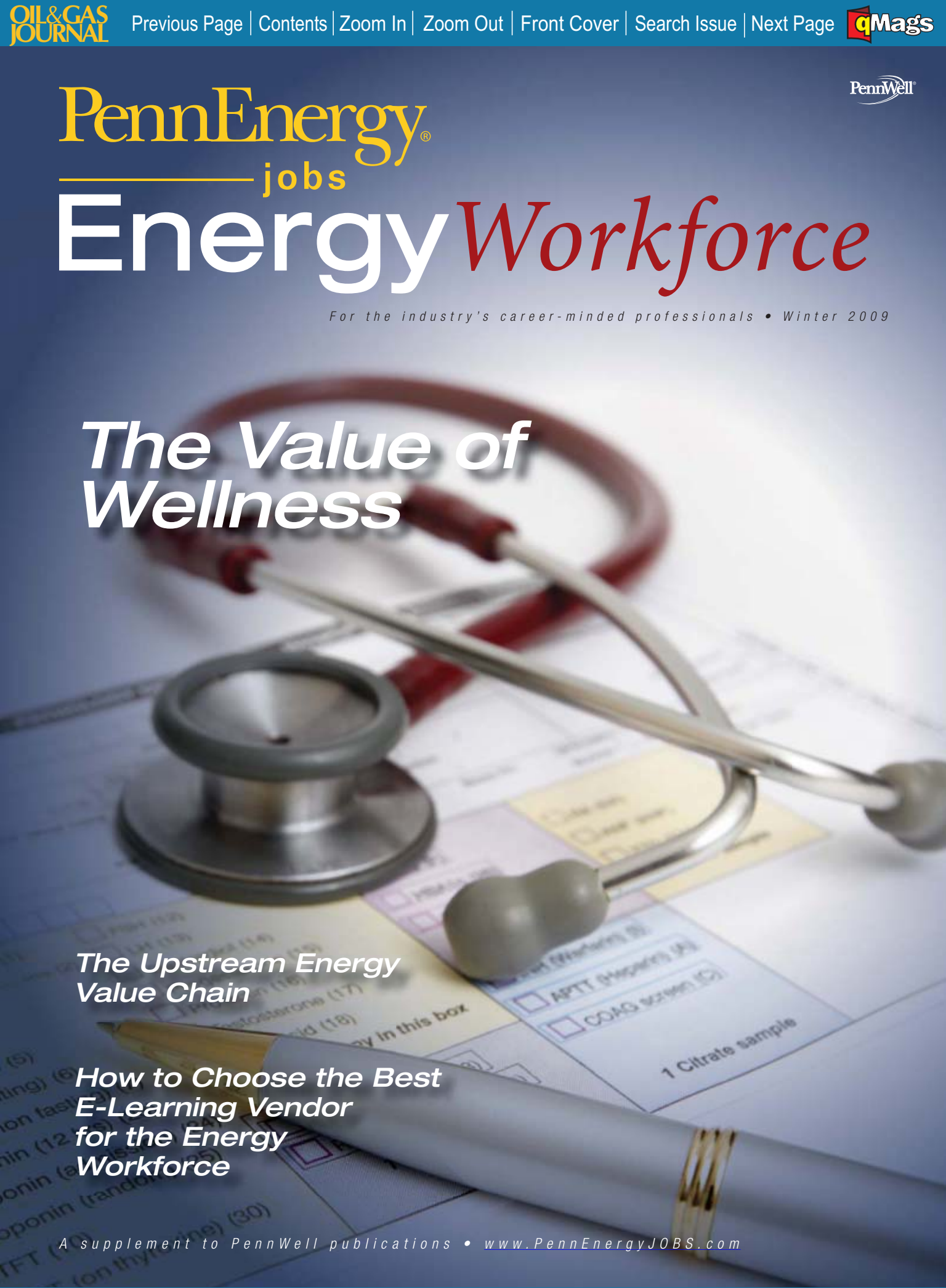

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Recruitment Practices and Generational Characteristics

As recruiting efforts slowly begin to increase, companies have the opportunity to incorporate generational characteristics into their hiring strategies.

Understanding the workplace differences between generations is more important now than ever. As companies look to hire over the next several years, they will interview and evaluate candidates spanning three age generations. Interviewers will meet with a multitude of candidates, and will come face to face with generational differences. Taking into account the foundational characteristics of each generation will add to a more robust assessment and selection of talent that meets organizational values and goals. So what should employers know about each generation?

First are the baby boomers. There are about 78 million baby boomers that were born roughly between 1946 and 1964. Baby boomers are characteristically loyal, work-centric, independent, goal-oriented and competitive. They believe that Gen-Xers and Y's lack work ethic and commitment to the workplace, and should conform to a culture of overwork. Baby boomers equate work and position with self-worth; they are clever, resourceful and strive to win. Boomers are well suited to organizations with a strong hierarchal structure, and may have a hard time adjusting to workplace flexibility trends.

Generation X is defined as anyone born between 1965 and 1980. Gen-Xers are the 46 million middle children who are sandwiched between 80 million baby boomers and 78 million Millennials. Generation X has an entrepreneurial spirit, thrives on diversity, challenge, responsibility and creative input. Gen-Xers were witness to the effects of their parent's burnout and layoffs, so they entered the workplace with different work ethic and culture than previous generations. Unlike the Boomers, Generation X places a premium on family time, and has a different attitude about work. They are ambitious and hardworking, but value work/life balance.

Finally, there are those who were born between 1980 and 2000, and are known as Generation Y (or the Millennials). Generation Y is smart, creative, optimistic, achievement-oriented and tech-savvy. Millennials are connected all over the world by email, instant messages, text messages and the Internet. This high speed, tech-oriented generation needs a variety of stimulating and creative activity in the workplace. Millennials prefer working in teams, seeks out creative challenges, personal growth and meaningful careers. They want to make friends with people at work, and work well with diverse coworkers. Some of the most noted characteristics of the Millennials are a need for constant reinforcement and a short attention span.

As recruiting efforts slowly begin to increase, companies have the opportunity to incorporate generational characteristics into their hiring strategies. Employers can better align these characteristics with their organizations structure, environment and culture.

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Manager, Staffing and Salary Administration, Human Resources
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The Value of Wellness

Building the Case for Wellness Programs in Remote Locations

By Tom Cooper, PhD, Mike Wahl, PhD(c), and Mike O'Neil

Organizations frequently ask specific questions around the cost of wellness. How much does it cost to run a 'best practice' wellness program, how much should our cost be relative to our risk in an approach to employee's wellness and are our current wellness arrangements cost-effective? The reason for focusing on cost is that financial directors, board members and human resources directors have all identified cost minimisation as a critical element in ensuring an efficient and effective approach to an employee's wellness as part of a wider human resources and operational strategy. We believe that examining the cost of wellness is just one part of the equation. Organizations also have to examine the value a wellness program provides.

Cost Minimization Vs. Value – Building the Case for Wellness

Cost minimization is just one element in examining wellness. Placed within the broader context of operating in a remote location, examining the cost and value of a wellness program becomes even more complicated. Further, when adding in a workforce that may be starting to experience increasing wellness issues – such as a predominantly male workforce engaged in blue or gray collar jobs – there is even further complexity for most organizations working in a remote location. Undoubtedly, cost minimisation is a critical element, but only one, of a wider approach to how well a wellness program operates – especially in a remote location.

Working in a remote location can be extremely stressful and demanding on an employee's wellness. Physical workload, dissatisfaction with safety and contingency measures are only some of the factors affecting wellness. Moreover, stress caused by intrinsic features of the job description and perception of risk (Ulleberg and Rundo 1997) are all issues for wellness programs to address in remote locations.

A wellness program needs to be seen an integral part of any organization's operations and cannot be considered a 'one-time' cost and subsequent short-term benefit. Instead, wellness has to be valued across an employee's time with an organization, the benefits accrued, the costs which are saved and the risks that are managed.

Working in Remote Locations – the Case for Wellness

After a number of high-profile disasters (most notably the Ocean Ranger disaster and Piper Alpha), oil and gas industry companies as well as other organizations working in remote locations are making every effort to ensure that their accident rates are kept as low as possible. The focus on 'accident' prevention is the main driver for most Health, Safety and Environmental (HS&E) programs. For most industrial accidents, there is a causal chain of organization conditions and human errors with Reason (1990) indicating that human-factors causes can be attributed to 70-80% of accidents in high-hazard industries.

Focusing solely on accident prevention is not a strategic approach to addressing wellness. Focusing on wellness, improving the overall organization's and employee's health is a significant way of driving down not only accident incidents but also overall operational cost.

Working in remote locations such as the offshore drilling process is inherently dangerous, arduous and socially isolating. The environment is characterized by constant noise and activity, and the employees live and work in a restricted working location for a period of time without any breaks. Most of the workforce is male, engaged in blue and gray collar jobs, and there is a significant portion of the population at risk especially when looking at key wellness determinants such as hip to waist ratio.

Consequently, the working environment in a remote location contains many environmental and organizational factors that are potential sources of ill health, i.e. demands in an individual's environment that are perceived to be a threat to the individual. The combination of heavy equipment, immense

physical forces and geological uncertainty with numerous personnel creates an overall risk to wellness.

Several studies on working in remote locations show an association between job stress, strain and health problems (Theorell and Karasek 1996; Ulleberg and Rundo 1997). Other studies have shown that social support – such as a wellness program - can have a positive effect on workers' well-being and health (Parkes et al. 1994). The need for a comprehensive wellness program in a remote location to manage stress, risk and employee health becomes clear. The question is whether the value that accrues to an organization is worth the cost incurred?

In years to come, shifts in industry structure (majors versus independents), aging infrastructure, deep water operations, new drilling and production technology, more complex wells, and the turnover of the owner and contractor operations workforce may affect company-level and industry-wide HS&E performance (Jablonowski 2006).

Wellness programs can be a major source of HS&E performance improvement. Moreover, by shifting the focus to value and cost savings there can be significant benefit accrued to the organization's operations – including direct costs such as decreased used of medicines, reduced medical benefits as well as indirect costs such as lower recruitment and training expenditures. Further, senior management, in trying to make or understand the case for developing a wellness program, can begin to model the cost. Through modelling the potential cost and subsequent value that a wellness program presents to organizations working in a remote location, the need for a wellness program becomes strikingly clear.

Sustaining Wellness

Wellness should be seen as a strategic issue. Our research with companies and individuals in remote locations shows that recognizing the strategic value of a wellness program can be quite positive for a company – specifically on brand awareness, equity as well as decreased recruitment costs.

HS&E programs centred on accident prevention cannot be sustained without a focus on wellness. Wellness programs are a primary tool in sustaining long term competitive advantage in operating in a remote location. Initial compliance based strategies focusing on short-term expenditures and not value may ultimately create more operational costs in the long term. Moreover, most health and safety programs do not recognize the value of taking a wellness approach. This means that there is not only a lack of long term value but a potential failure of corporate responsibility and ultimately a loss opportunity for performance improvement.

Employers have a corporate responsibility to provide a safe workplace to enact measures to reduce the likelihood that employees are injured (Jablonowski 2006). There are also direct economic consequences of HS&E events, and it is in an organization's best economic interest to improve wellness performance.

Estimates suggest that it costs between $50,000 and $100,000 to administer a lost time injury (Buchan 1999). This does not include other costs such as lost productivity, sick pay, equipment damage, increased medical premiums, the cost of medicines to treat the injury, increased insurance premiums or costs of legal action should a claim arise, which could be several times as much (Flin and Slaven 1996; Sumrow 2002; Jablonowski 2006). Moreover, it does not include operational costs such as the extra recruitment needed to replace workers, additional workforce to provide excess capacity in the case of accident and time away from work as well as training for new or replacement workers.

Moreover, given the spotlight on companies conducting business in remote sites, especially from opponents in many of the locations where they operate, means that organizations must remain proactive if they intend to maintain their overall license to operate. Critics often cite HS&E performance as a reason to limit exploration and production (E&P) activities (Brinded 1998; Gidley and Hall 2002). Wellness programs can therefore be seen as a license to operate issue.

Companies with good wellness performance should incur lower compliance costs. Also good performance across the industry may drive broader reform than reduced compliance costs. Clearly companies benefit both individually and collectively from improved HS&E performance focused on wellness.

What is meant by Value of Wellness?

For the purpose of this article, we want to focus specifically on three concepts related to the value of wellness:

Wellness value – the overall value (both financial and operational) that an approach to wellness gives an organization, its employees and other stakeholders

Wellness risk – the risk of impairment to the organization's business model, operations, reputation, and financial condition from failure to address wellness. This means that the organization does not meet expectations of key stakeholders such as customers, employees (both current and future) and society as a whole, laws and regulations as well as internal standards and policies.

Wellness Programs - the proactive mechanisms by which organisations exploit and manage wellness risk.

When organisations talk about 'wellness cost' essentially they should be focusing on the costs of identifying and controlling **wellness risk** as well as developing the proactive mechanisms of a comprehensive wellness program.

Regulators and other stakeholders may take a more narrow view, for instance, looking at wellness costs as specifically those related to reducing accidents and other health and safety incidents. However, taking a holistic approach to wellness is more appropriate to the everyday health and safety manager, human resources director, as well as the broader operations within an organisation.

For example, Gerard has just been hired to work at your offshore oil rig. An experienced welder, he has worked in the field for over fifteen years starting at the age of 22 in the Gulf of Mexico. His job is physically demanding and is a specialized skill set for your offshore operations. Gerard is moderately overweight and after a year working with you has developed obesity and extreme hypertension. This is predominantly because of your nutritional policy on board the rig and the lack of a wellness program. Gerard is advised by his Doctor to go off work and to start an expensive round of medicine to combat the illnesses. You are also forced to recruit an additional welder and this has to be done in quite a short timeframe as Gerard operates on a three weeks on, three weeks off period.

So in Gerard's case, there are costs and issues to be addressed by the health and safety manager, human resources director and by operations. However, if Gerard's continuing wellness

issues are not addressed then there are significant issues related to critical illness as well as potentially death.

Understanding that addressing wellness is directly linked to senior management and its concerns about how individual liability risks are being addressed is also key in understanding its value. Ultimately, the value of a wellness program is derived from operations cost savings as well as risk management.

The Cost of Wellness for Senior Management

For Health and Safety directors, focusing the 'cost' of wellness on identifying and controlling wellness risk within a specific department or business unit may be sufficient.

However, for finance directors, CEOs, board members and other stakeholders, there may need to be a different approach to costs. For them, cost can normally relate to a number of areas, including:

- **Cost of Recruitment** – the cost of recruiting new staff since existing staff decided to leave due to health related reasons
- **Cost of Retention** – the cost of retaining existing staff
- **Liability** – costs related to issues which lead to death or critical illness
- **Medicine and Medical** – programs that add cost to the organization
- **Wellness activity-based costs** –cost of activities such as monitoring health, policies towards wellness, oversight, reporting, rectification etc.
- **Remediation** – the cost of remediation to employees as well as any related internal costs and those associated with disciplinary action, e.g. fine for health and safety violations
- **Business review** – the cost of assessing whether there are problems in the business related to wellness – including root cause analysis

For Executives, Board members and finance directors, the actual cost of a wellness program is relevant only with respect to its performance and value to an organization.

If the wellness program does not perform or meet expectations, then there is an increased risk to the business and individual senior managers/directors. If this risk is not addressed, the result may be increased fines, considerable medical premiums including medicine costs, individual liability for health related failings, employee retention issues with the associated costs and risks, potentially significant remediation costs and license to operate issues.

At its core, the question senior management has to ask itself is, given the current level of costs, is the existing approach to wellness performing adequately, and what is the quantitative value a wellness program should be providing for the organization?

Overall Value of a Wellness Program

Definitions has developed a model to examine the cost and value of wellness looking at both direct and indirect costs an organization might face in failing to address risks pertaining to wellness. Taking all the direct costs together, a wellness program can assist in a cost savings of up to $125,000 per employee on a yearly basis within an employment lifecycle when seen within the entire spectrum of operational costs.

There are also a number of 'one-off' costs that can be saved by having a wellness program. The 'one-off' costs such as Time Away from Work, Training and Recruitment could save a company an additional $150,000 over the employment lifecycle. Based on a twenty-year lifecycle, this will result in savings of $2.650 million – excluding the potential costs of death and critical illness which would potentially double that amount.

Ultimately the value is not only direct cost savings, Intangibles such as brand equity and license to operate are issues that must also be considered. For senior management, direct cost savings can be estimated using activity based costs, and it is clear that there are significant direct costs that a wellness program may prevent over the course of an employee's time within an organization.

For senior management, the 'bottom-line' number for the business case for wellness will clearly depend on the organization, its operations and the nature of the work in remote locations but nonetheless, the value of a wellness program becomes clear.

Conclusion

At Definitions, we believe that the cost and value of a wellness program has to be considered both from a 'bottom line' and 'forward-looking' perspective. Our research and working with numerous industries, companies and employees in remote locations, has demonstrated to us that the cost of a wellness program should be seen primarily from savings accrued to an employer throughout the time an employee works for a company – the baseline for the overall value of a wellness program to an organization.

Savings through the establishment and implementation of a comprehensive wellness program can be seen, not only from a health and safety perspective, both also from operational effectiveness. We believe our research shows that there is significant value accrued to an organization through the establishment of an effective wellness program. —EW

About the Authors

Mike Wahl is co-owner and director of Definitions Fitness Company. He is a PhD candidate in the faculty of medicine at memorial university in the field of epidemiology. He holds a masters degree in applied muscle physiology from MUN and a bachelors degree in kinesiology science from UNB as well as various other professional certifications. Mike is also the host of Power Living on NTV, been featured on Daily Planet and has had articles published in peir reviewed literature as well as over 50 popular media sources including the Journal of strength and conditioning research, the IADC's drilling contractor and the financial post. He has presented in Europe for the International Association of Drilling Contractors HSE conferences and most recently at OTC in Houston both for his work in the on and offshore oil industry in Atlantic Canada. Mike was also named the BDC Young Entrepreneur of the Year for Newfoundland in 2005, a top 3 finalist for the Ernst and Young Entrepreneur of the Year for Atlantic Canada in 2007 and listed on the Government of Canada's website as an Inspirational Youth Leaders.

Dr. Tom Cooper hails from St. John's, NL. He graduated from Memorial University in 1993 with a Bachelor of Arts in philosophy and a Bachelor of Commerce (co-op). For the last 15 years,

however, he has studied and worked in the United Kingdom, first as a PhD student at the Warwick Business School, University of Warwick, and later, as a senior manager in PricewaterhouseCoopers' Performance Improvement Consulting practice. Now, as one of the Faculty of Business Administration's newest assistant professors, Dr. Cooper said he's "getting used to the cold again."

In London, Dr. Cooper worked as a senior consultant with clients throughout the United Kingdom, Europe, and North America, primarily in the area of compliance and regulatory risk within the financial services sector. He also worked on a large number of international projects for clients on compliance and regulatory process improvements around areas such as data protection and privacy.

Dr. Cooper's research is primarily focused on the interplay between governance, risk, and compliance and their effects on corporate responsibility as well as accountability. At Memorial, he lectures at the undergraduate and graduate levels in the areas of strategic management and business and society.

An avid athlete and health enthusiast, **Mike O'Neil** possesses a master's degree in health and physical education and is currently completing his PhD in Natural Health. Mike's skills were developed over time as he has co authored many articles in health and wellness as well as executed over 10,000 hours of wellness counseling. Mike greatest strength comes in his ability to teach and counsel normal populations in health and wellness. Mike co–created the trademarked 7 habits of power living system which teaches people a basic and holistic approach to wellness and empowers the individual to take responsibility for their own health and wellness through education.

Definitions is an industry leading fitness and lifestyle company that specializes in Power-Living for individuals and companies. Power Living is defined as having maximum in energy in all aspects of life as you define them, meaning that Definitions real world approach to wellness offers the greatest possibility for individual and corporate success. All of Definitions services, products and programs are supported by post secondary education, real world experience, and a gimmick free methodology. Definitions Fitness Company services several industrial and corporate clients including major oil and gas entities, production plants and office settings. Definitions personnel travel directly to the worksites including offshore oil and gas establishments and office settings to improve the wellness and safety culture of the organization.

The Upstream Energy Value Chain

By Kripal Kavi

The energy value chain is one that is intrinsic to the existence of the world as we know it today. It is an industry that is more than 150 years old and is one of the most complex in the world today. By the very nature of its product, this business is subject to risks such as geo-political risk, business risk, financial risk, credit risk, market risk, currency risk – the list continues. However, the very existence of these multitudes of risk serves to show that a career in the energy industry can be both, financially and personally rewarding.

Exploration and Production: Known as E&P for short, this label describes the activities associated with finding oil and natural gas and getting them out of the ground. This area of the energy value chain is also referred to as "upstream." Firms in this area specialize in activities such as seismic surveying, drilling (offshore and onshore), rig construction, land management, etc. They build, operate and manage rigs independently or for large integrated oil companies. As a result of their operations, these organizations tend to be large, geographically diversified and capital intensive. Also, this is a fairly fragmented industry with 7 – 8 companies owning just 25% of the market share. Profit margins here are directly tied to the price of crude oil and are typically among the highest in the energy value chain.

Most integrated oil companies[1] and national oil companies[2] have captive E&P divisions, but occasionally do hire independent E&P firms on a project-by-project basis. Career opportunities here are most commonly available for petroleum/chemical engineers, geological engineers, land management experts and civil engineers. Opportunities for business folk are limited and would most involve positions such as accounting, supply chain management and to an extent, HR.

Refining: Refining initiates a segment of the energy value chain that is collectively referred to as "downstream." Historically downstream activities have proved to be less profitable than upstream. As a result, the industry is dominated by larger organizations that also have E&P activities. Similar to E&P, this industry is also capital intensive, but typically tends to be geographically localized. The profit margins in this industry are typically low and are inversely proportional to crude oil prices. With increases in crude oil prices, demand for their products decrease while costs for raw materials (crude) increase. The US government, from time to time, to compensate for diminishing profit margins, has subsidized small players within this industry. However, this subsidy has been gradually decreasing over time, leading to the closure of a number of independent refineries.

As with E&P, most IOCs and NOCs have captive refining divisions. Diminishing profit margins within this industry in the 1990s led to a number of refinery closures with refinery count in the US dropping to low of 144 in 2002 from over 300 in the mid to late 1980s. Opportunities here are mostly limited to chemical engineers, refinery operators and operations managers.

Trading: Crude oil is the most commonly traded commodity in the world today. Huge volatility in prices and a tightly controlled supply have driven the growth of oil trades in the commodities trading industry. The role of firms within this space is to act as either brokers or dealers. As a broker, these firms are usually hired by other energy companies on a commission basis to engage in the buying and selling of crude oil spot contracts, futures and options. In contrast, as dealers, the trading companies take actual positions in the oil. In other words, they actually own the oil that they trade and are typically captive divisions of larger organizations involved in other activities on the energy value chain.

The commodities trading industry is heavily fragmented with most financial services institutions participating in some form

or the other. Given the global nature of the underlying asset, organizations tend to have operations in multiple geographies. The industry experienced significant growth over the last few years preceding the financial crisis of 2008. Given the largely variable cost structure driven mainly by labor, this industry can adapt quickly to changes in the economy. Typical careers in this industry consist of positions such as commodity trader, currency trader, risk manager, treasury, information technology and economist/analyst.

Transportation and Storage: This industry executes the transportation of crude oil and other refined products. In certain cases, firms also own large storage areas where crude oil and related products can be staged before they are actually utilized. The main mode of transportation of oil is pipeline. Due to increased dependence on foreign oil and oil imports during the last few years, the volume of product being transported by these networks has gradually decreased. Also, prices for transportation services has remained fairly constant as a result of which revenues within this industry have been steadily declining over the past few years. The revenues within this industry are forecasted to decline further over the next few years due to increased imports and fixed prices. And since this is a high fixed cost industry, the decline in revenues will directly impact profitability.

Major oil companies usually have their own transportation networks. Opportunities within this industry include positions for civil, mechanical and chemical engineers, environmental engineers and accountants.

Retail: Retail services include the actual marketing and selling of the final refined products to the consumer and/or corporations. This industry is broadly classified into firms that deal primarily with fuel oil and others that deal with gaseous products.

Margins within this space are declining, and the industry has consolidated significantly over the last few years. The operations here are primarily related to the selling of gasoline, diesel oil and other fuel oils to individual consumers. With the consolidation, employment within this industry has also been gradually declining. The roles most commonly available in this industry are related to the areas of procurement, accounting, supply chain operations and marketing.

The sub-industry that deals with gaseous fuel products is heavily fragmented with the top four firms having a market share of just 15% in 2009. These firms engage in the sales and distribution of gaseous fuels such as Propane, Natural Gas and LP gas to corporations such as utilities. The industry has been steadily profitable and is subject to lesser volatility, as natural gas prices do not fluctuate as wildly as crude prices. However, the recent crashes in fuel prices have dampened profits within this industry as well, which is largely capital intensive. Opportunities within this space are available in the areas of supply chain and logistics, accounting, information technology and sales operations.

Electricity Generation and Distribution: Currently in the US, electricity generation and distribution is regional, with each geographic region usually having only one or two major players. Prior to the 1990s, this industry was heavily vertically integrated with firms involved in generation and distribution activities. However, now there is a clear segmentation between electricity producers and distributors.

The power generation industry is moderately fragmented with a high level of competition. With the recent developments in distributed generation from renewable sources such as solar and wind, the number of independent power generators is growing. Revenue increases in this industry are driven largely by increases in electricity prices and not additional volumes. And projects here typically tend to be very long term – in the range of 30 to 40 years. Recent concern over GHG emissions has caused increased interest in natural gas, nuclear and hydroelectric plants. Most utility companies source part of their electricity in-house from captive assets, and the remainder from a highly fragmented market of individual power generators. Opportunities here are available for mechanical, process and civil engineers, accountants, contract analysts and procurement specialists.

The power distributors, as the name suggests are primarily involved in power transmission and distribution. The revenues in this industry are directly tied to power consumption, which in turn is very highly correlated to the state of the economy. Profit margins within this industry are highly regulated as a result of government bodies constantly regulating prices. There is a wide range of positions available within this space, ranging

from sourcing, supply chain, contract management, marketing and sales to accounting, finance and government relations.

Energy Consulting and Other Services: As mentioned above, the energy value chain is extremely complex and is influenced by innumerable factors. Thus, it becomes challenging for energy companies to develop absolute competencies in all the different areas. This provides the market opportunity for a number of energy services firms that work with energy companies in various settings. This space consists mostly of consulting firms and financial services firms.

There are a number of consulting firms (generalist and boutique) that offer consulting services to energy companies. The topics consulted on range from engineering-heavy areas such as geology and rig construction to economics-related spaces such as strategy, market research and project due-diligence. Employee turnover within the consulting industry tends to be on the higher side due to extensive travel and these firms are constantly on the lookout for new talent. Individuals who have been in the industry for a long time or who have significant consulting experience are prime hiring targets for these firms. Due to the specialized nature of these services, margins tend to be very high.

As energy is a very capital-intensive industry, financial services firms play a key role in the value chain. These firms provide transaction advisory services, trading expertise, capital raising activities and in some cases, even project valuations for large energy firms. There are a number of boutique energy focused financial services firms. And there are firms that perform both, consulting and financial services activities. As with the consulting firms, individuals with intricate knowledge about the energy industry or with prior investment banking experience are highly sought after.

Energy – a growing opportunity

As you can see, the energy value chain offers opportunities to people from a wide variety of disciplines. Opportunities range from technical roles such as engineering and operations to business roles in finance, strategy, marketing and economics. All said and done, energy is intrinsic to all human activity, and as a result, is a key strategic resource for countries. This makes the industry fundamental to national security. And the importance of this industry to the world will increase multifold over the next few years as a result of increasing consumption and potentially finite resources.

A survey of energy companies conducted in 2007 by Oliver Wyman, a consulting firm, revealed that most energy companies are expected to face a severe talent crunch over the next five to ten years[3]. The main drivers for this are an increasing number of employees approaching retirement age and a dearth of skilled talent. The recent changes in the economy since then have somewhat altered the latter, but the first challenge still remains. As a result, opportunities in this industry are anticipated to grow over the next few years. Individuals interested in working on complex problems in a truly international environment, with relatively high job security and competitive remuneration should definitely give energy a second look. —EW

About the Author

Kripal Kavi is currently enrolled in a three-year MBA/MS program at the University of Michigan. Prior to Michigan, Kripal led product development and deployment teams at SAP AG. Last summer Kripal interned with Amazon.com in their Pathways Operations Leadership development program. Currently at Michigan, Kripal is an officer of the Operations Club, a member of the energy club and is enjoying keeping time as the drummer for the Ross Hard-Rock band. He is extremely passionate about the energy industry and is interested in pursuing a career in traditional and renewable energy.

The Ross Energy Club (REC) is a group of talented business students who share an interest in energy. REC promotes career development by providing a forum for education about all aspects of business in the energy sector. REC offers opportunities for students to discuss and learn about subjects such as strategy, trading, finance, project development, public policy, and entrepreneurship within both traditional and renewable energy sectors.

References

[1] IOCs are oil companies that perform most activities on the energy value chain

[2] NOCs are oil companies owned by the governments of the host country

[3] Source: http://www.oliverwyman.com/fr/pdf_files/GAS24_05proof_orr.pdf

RECRUITER'S PRACTICUM

How to Choose the Best E-Learning Vendor for the Energy Workforce

By Peter Schmidt and Carolyn Pyrek

Within the energy sector, the greatest change driving the need for improved approaches to learning and employee development is the demographic reality of an aging workforce within every professional discipline. Referred to in many energy industry studies as the "big crew change", the retirement pattern of skilled senior personnel over the next five to 10 years will require significant transfer of responsibility to new employees. One of the critical actions being taken in response to the rapidly approaching tipping point is education – transferring knowledge to the next generation of engineers and technicians.

Education is making a critical contribution to addressing the exiting expertise problem within the energy sector. Industry is enhancing in-house education and training capabilities often by working with educational organizations to develop new approaches to career-long learning.

While professional development remains an essential part of organizational health, it can be costly, too. Per capita training budgets in companies across the sector ranged from $4,000 to $8,000 in a recent survey conducted by *EnergyWorkforce*, with this cost expected to increase in coming years. The use of technology to deliver learning content has increased proportionally and companies are spending more on external services like content design, development and technical infrastructure for training delivery.

For five consecutive years, we have seen a significant upswing in online classroom enrollment as companies shift from in-person to online instruction to save on travel costs, reach geographically dispersed workforces and ensure consistent content delivery. According to current research, virtual learning, whether in real time or at the learner's own pace, differs little from live classroom training. Given the range of e-learning vendors available, it can be confusing at best to select the right online learning program. What should a training manager look for when evaluating Web-based training? How can he or she be sure that the program will be effective?

According to Work-Learning Research, there are eight principles to which an effective virtual learning program should adhere. When evaluating various vendors, CLOs would do well to consider the following points: learning contexts, practice and testing, level of feedback, repetition, learning over time, diversified material presentation, exclusively relevant information, and focus. Following are questions to ask when undergoing the selection process.

1. Aligning Learning and Performance Contexts

- Does the program contain integrated, energy-specific case studies that bring elements of the job into the online classroom?
- Does it contain realistic scenarios that provide context for each lesson?
- Do the lessons evaluate understanding by posing problems or challenges similar to the ones the learner may encounter on the job?
- Is there an opportunity to discuss, with an instructor/subject matter expert (SME) and with other students, how concepts apply to actual situations on the job?

2. Providing Retrieval Practice and Testing

- Does the program offer a pre-course assessment to establish the learner's knowledge baseline?
- Does each lesson contain a problem that tests the learner's understanding and ability to apply the lesson concepts?
- Are assignments, with feedback, a requirement?
- Is there a final exam at the end of the course? Note: Research shows that the very act of taking a test increases retention, even if the learner didn't study at all!

3. Providing Feedback on Practice and Testing

- Is there a feedback system in place in the event the student answers a lesson problem or final exam question incorrectly?
- Do all practice exercises within the online courses also provide the correct answer and a complete explanation?
- Do the students receive personalized feedback from an expert instructor/SME within 24 hours after submitting an assignment?

- Do the instructors participate actively, on a daily basis, in online discussions, providing personalized feedback to the users' postings?
-

4. Providing Repetition of Learning and Practice

- Does every lesson reinforce the challenges the learner would experience on the job?
- Are the assignments hands-on? For instance, do they just learn about the work breakdown structure (WBS), estimating methods, network diagrams, and project earned value—or do they actually build a WBS, estimate a project, construct a network diagram and calculate earned value?
- Do the exercises and instructional games, as well as the final exam, provide additional practice?

5. Spacing Learning and Practice over Time

- Are the students given a timeframe within which they must complete the course?
- Is the content "chunked" into a series of lessons, making it easy for the learner to complete one lesson at a time?
- Is it a self-paced program that provides a guideline schedule to help learners plan and budget their time?

6. Presenting Learning Material in a Variety of Ways

- Is the course material diversified in terms of its delivery format, avoiding the dreaded "next, next, next" sequence of a slide show?
- Is the presentation of the content interactive and student-centered, allowing students to access content at will and to control at least some of the sequencing?
- Is the interactive content supported with additional online text in printable, PDF format?
- Does the course offer engaging and often interactive graphics to help learners visualize processes and relationships?
- Do the courses also offer practice exercises, problems, assignments, and online discussions—all with feedback—to reinforce the content?

7. Utilizing Relevant Information Only

- Is all content relevant to the course content—or are there gratuitous animations and gimmicky flash?
- When there are comics and games, are they clearly instructional and tied to specific learning objectives?

8. Helping Learners Focus on the Most Important Information

- Does the course supply a syllabus that summarizes the major topics covered in each unit and identifies the specific learning objectives for each unit?
- Do scenarios and problems emphasize the key focus of the lesson?
- Are there opportunities to complete exercises that strengthen the emphasis?
- Do the individual content resources incorporate sound design principles in order to clarify and emphasize important points, including screen layout, font size and type, and graphic design?
- Are all the questions on the final exam tied to a specific learning objective, ensuring that the test itself continues the focus on core content?

If you answer 'yes' to every question, you can have confidence that the program you are reviewing is instructionally sound and that users will retain and be able to apply their newly acquired knowledge and skills. But, if you see gaps in the program's offering, move on until you find the most appropriate online course to match your needs. The selection process will be less arduous if you know what you are looking for. The importance of establishing top-quality, versatile e-learning programs for your most important resources–the people you employ–cannot be overstated. Evaluating the available courses beforehand will improve your chances of

Evaluating the available courses beforehand will improve your chances of success, strengthen your return on investment and ensure a vibrant learning organization in the long term.

success, strengthen your return on investment and ensure a vibrant learning organization in the long term.

The exodus of technical expertise in the energy sector will continue to accelerate. It is necessary to view this exodus not as a short-term problem, but as a long-term opportunity to train and develop a more versatile, skilled and technically savvy generation of engineers and technicians. Decisions on investments in people are just as important as the decisions on investments for infrastructure and capital equipment. E-learning helps to create an organizational capability for self-renewal through knowledge retention and transfer. These new and innovative learning models incorporate the best of people and technology to optimize the effectiveness of scarce human and financial resources. *—EW*

About the Authors

Peter Schmidt, Director, Engagement Management, ESI International, has almost 20 years experience as a project management professional and has spent more than a decade focused on the energy industries in North America, Europe and the Middle East.

Carolyn Pyrek, PhD, Director of Curriculum Development, ESI International, has more than 20 years experience developing learning programs for adults. Her duties at ESI include overseeing the company's global e-Learning offerings.

About ESI International

ESI, a subsidiary of Informa plc (LSE:INF), helps people around the world improve the way they manage projects, contracts, requirements and vendors. In addition to ESI's more than 100 courses delivered in 22 languages at more than 85 locations worldwide, ESI offers nine certificate programs through our educational partner, The George Washington University in Washington. Founded in 1981, ESI's worldwide headquarters are in Arlington, Va., USA. To date, ESI's programs have benefited more than 1 million professionals worldwide. For more information visit www.esi-intl.com.

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POWER Engineering

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Sunday, December 6, 2009 – COMPETITIVE POWER COLLEGE Pre-Conference Workshops				
8:00 AM – 5:00 PM	CPC 101 Room N102 Basic Gas Turbine Metallurgy and Component Repair	CPC 102 Room N103 Understanding Fossil Power Plant Performance Using First Principles Models	CPC 103 Room N107 An Introduction to the Design, Operation and Evaluation of Parabolic Trough Solar Power Plants	

Monday, December 7, 2009 – COMPETITIVE POWER COLLEGE Pre-Conference Workshops				HALF-DAY WORKSHOPS	
8:00 AM – 5:00 PM	CPC 301 Room N103 Capital Project Analysis at Power Plants	CPC 302 Room N107 Essential Practices for Outage Management	CPC 303 Room N108 Turbine Generator Failures: Prediction and Prevention	CPC 304 Room N111 Lost Efficiency: Finding "Low Hanging Fruit"	8:00 AM – 12:00 PM	CPC 501 Room N101 Why Good Projects Don't Get Built

Tuesday, December 8, 2009						
9:30 AM – 11:30 AM	*OPENING KEYNOTE ADDRESS* *Las Vegas Hilton* *Barron Room* **Mr. Michael Yackira** **President and Chief Executive Officer** **NV Energy**					
Conference Tracks & Sessions	Industry Trends / Competitive Power Generation I Room N109	Industry Trends / Competitive Power Generation II Room N110	Environmental Issues I Room N103	Environmental Issues II Room N111	Fossil Technologies I Room N107	Fossil Technologies II Room N108
1:30 PM– 3:30 PM	Integrating Renewables with Thermal Generation – Panel Discussion	Streamlining Project Approval – Panel Discussion	NO_x Control: Issues and Strategies	Mercury Test Results and Issues	Modern Coal Plants & Design Developments	Material Handling Challenges and Solutions

Wednesday, December 9, 2009						
7:30 AM – 9:00 AM	Networking Breakfast – Ballroom C, Las Vegas Hilton					
9:30 AM – 11:30 AM	The Stimulus Plan's Effect Advanced Generation Technologies	Three Optimization Approaches to be Cost-Effective Today – Panel Discussion	Regulatory Issues and Environmental Compliance	CO_2 Abatement Strategies	How Carbon Capture Affects Plant Design	Biomass and Biomass Co-Firing Considerations in Coal-Fired Power Plants
1:30 PM – 3:30 PM	Renewable Electricity Standards and Their Impact on the Electric Power Industry – Panel Discussion	Smart Grid, Renewables Integration and System Security – Transmission Trends Affecting Power Generators	Advances in Multi-Pollutant Control Technology	Control of SO_2 and SO_3 Emissions	Pre- and Post-Combustion CO_2 Reduction Technologies	Innovations in Gasification and IGCC

Thursday, December 10, 2009						
7:30 AM – 9:00 AM	Networking Breakfast – Ballroom C, Las Vegas Hilton					
9:30 AM – 11:30 AM	Mega-Session Room N110 Preparing for the Upcoming CO_2 Capture / Sequestration Legislation – Panel Discussion				Mega-Session Room N112 Large Frame Gas Turbines	

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	HALF-DAY WORKSHOPS			TWO-DAY COURSES
CPC 104 Room N108	1:00 – 5:00 PM	CPC 402 Room N101	CPC 403 Room N115	**8:00 AM – 5:00 PM each day**
Power Plant Construction Management – A Guide to Survival		Turbine Generator Torsional Vibration Failures Prevention: 40 Years of Problem Solving Experience	Intellectual Property Fundamentals for Renewable Energy Developers, Licensors and Licensees	

CPC 502 Room N102	1:00 – 5:00 PM	CPC 503 Room N101	CPC 504 Room N102	CPC 505 Room N113	**CPC 201** Room N109
Temperature Measurement and Data Acquisition in Power Plants		Key Considerations and Best Practices in EPC Contracting for Wind Farms (Developer's Perspective)	Turbine Inlet Cooling: The Energy Solution to Increase Power Output, Lower Emissions, Decrease Carbon Footprint & Improve Heat Rate	Combustion Dynamics in Gas Turbine Power Plants	Heat Rate Awareness and Carbon Reduction

Mr. Pierre L. Gauthier
President & CEO
ALSTOM Canada Inc. and ALSTOM US Inc.

Mr. Keith Rattie
Chairman, President and CEO
Questar Corp.

Gas Turbine Technologies **Room N113**	**Renewable Energy I** **Room N112**	**Renewable Energy II** **Room N114**	On-Site Power **Room N117**	**Plant Performance I** **Room N101**	**Plant Performance II** **Room N102**
Gas Turbines – An O&M Perspective	**Biomass Market and Technology Developments**	**Utility-Scale Solar Power**	**Net Zero: Blending Technologies to Achieve Grid Independence**	**Performance Improvement Through Instrument, Control and Electrical Systems**	**Gas Turbine Inlet Cooling Improves Output and Emissions**
Combined Cycle Technology Update	**Wind Power**	**Emerging Clean Technology Innovations**	**How Distributed Energy Technologies will Integrate with Tomorrow's "Smart Grid" – Panel Discussion**	**Plant Maintenance**	**Steam Turbine Reliability, Availability & Efficiency**
Advances in Gas Turbine Technology	**Biomass Fuels for Power Generation**	**Energy Storage**	**The 2010 ESCO Model – How to Overcome the Capital Cost Hurdle – Panel Discussion**	**Asset Optimization**	**Combustion Optimization and Boiler Cleaning**

	Mega-Session **Room N114**
	Renewable Power Survival – Panel Discussion

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